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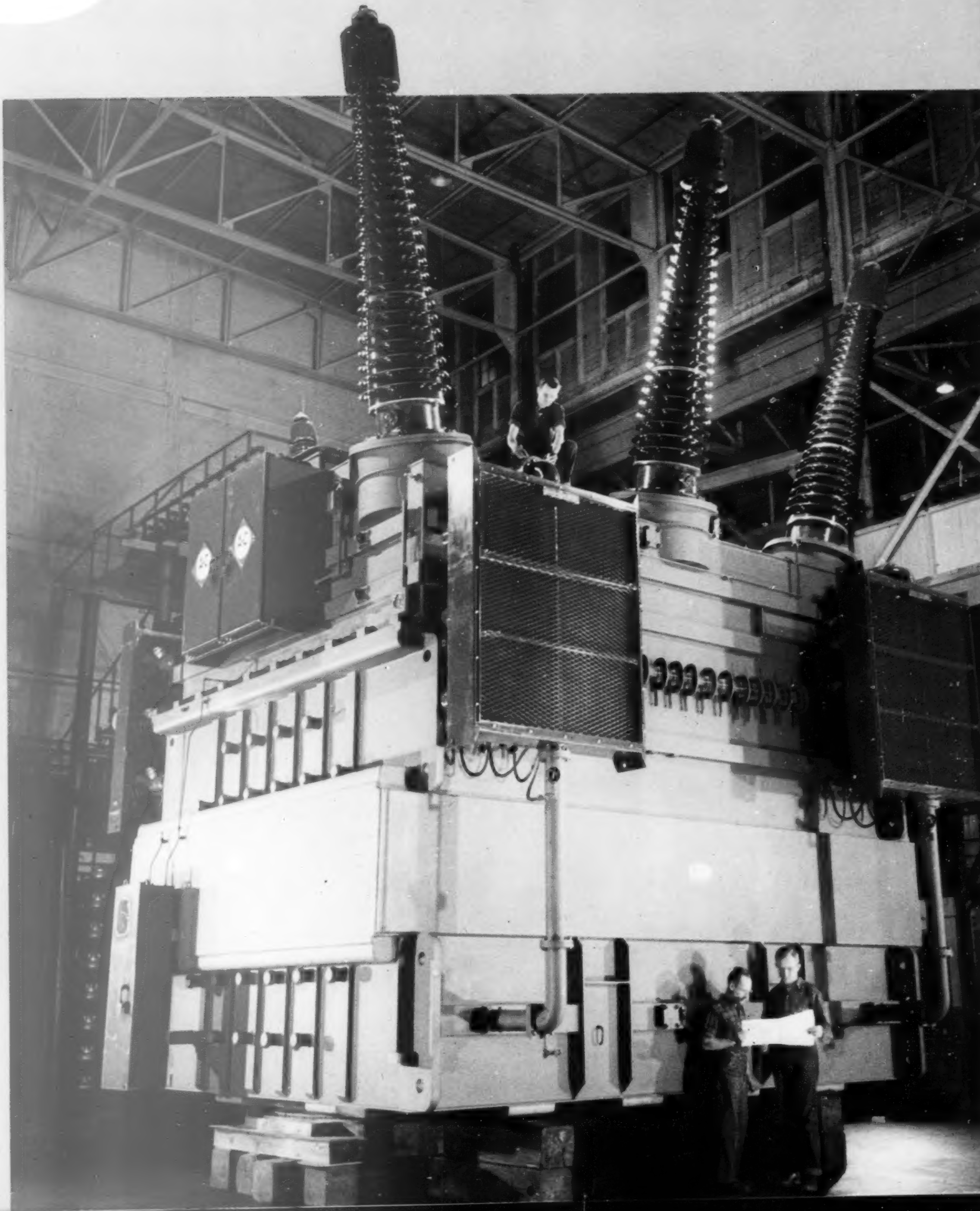
Electrical REVIEW



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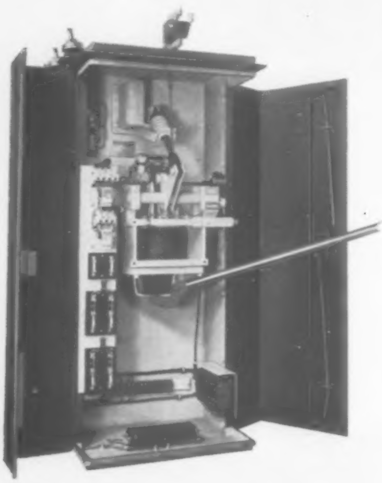

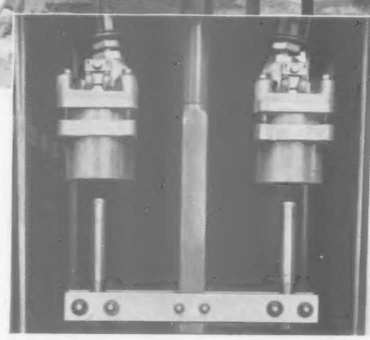

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Electrical REVIEW

THE COVER

IN TRIMMING TONS from this 125,000-kva, 330 to 135-kv autotransformer, horizontal core construction was used and the tank assigned the extra function of core clamping. Smaller physical size and reduced oil requirements resulted. Two of these units are being built for the Ohio Valley Electric Corporation's Pierce Station near New Richmond, Ohio, and two more are being built for the Clifty Creek Plant of OVEC's subsidiary, Indiana-Kentucky Electric Corporation. As a precaution against possible high water at the latter location, these transformers have the *Electro-Coolers* and controls nearly nine feet above the base.

FULL-COLOR cover and center spread pictures taken by C. Hansen and M. Durante, Allis-Chalmers Staff photographers.

Allis-Chalmers

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MOTOR STARTING...

A Distribution System Problem

PART I

by **H. W. CORY**
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Frequently line voltage stability can be improved by coordinating motor-starting sequence and starting methods.

WHEN PLANNING A NEW PLANT or an expansion of present facilities, considerable thought must be given to the power distribution system — the effect the system has on motor starting and the effect motor starting has on the system. The capacity of the system to handle motor-starting currents may be a major factor in the choice of both motors and controls.

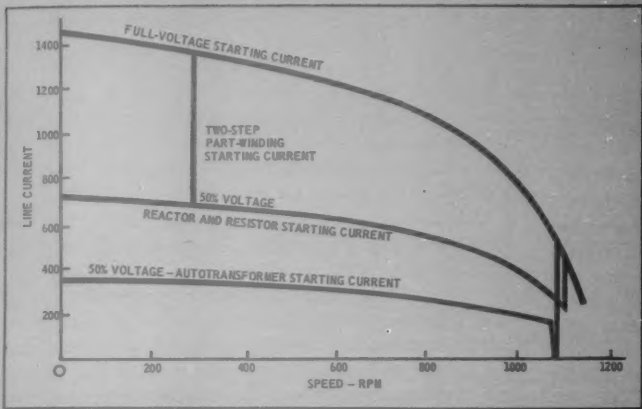
Since today's standard ac motors are designed for full-voltage starting, they should always be started on full voltage when line and load conditions allow. Full-voltage starters are simple and economical, and have no size limitation. Motors as large as the six 22,500-hp synchronous motors recently installed in an irrigation system for driving pumps are being started on full-line voltage. However, a special line from Shasta Dam is required to feed power to these motors.

TYPICAL LINE-UP of 4160-volt, 250-kva interrupting ca ity, fused motor controllers, rated from 300 to 2000 hp, installed in northern Michigan copper-refining plant. Inclu are full-voltage cage and wound-rotor motor controll

Reduced-voltage motor starters are used only when the distribution system cannot maintain its voltage during the motor-starting inrush or when the driven load cannot stand the shock of a sudden start. Such loads as conveyors, elevators, hoists, feeders, and certain machine tools frequently fall into the latter group.

The most important factor influencing motor starting is the stability of the power system on which the motors operate. When polyphase ac motors, either the squirrel-cage induction or synchronous types, are started on full voltage, the current required to break away and accelerate the motor is several times full-load current, diminishing as the motor gains speed. Figure 1 shows the full-load starting current of a 200-hp, 440-volt, three-phase, 60-cycle, 1200-rpm Code F motor. The locked-rotor current or current at instant of starting is about six times full-load current. This means that the power system must be capable of furnishing six times more kva to start the motor than it has to supply to operate the motor at full load. The starting current for any polyphase squirrel-cage or synchronous motor will be several times full-load current but will vary depending upon the torque characteristics of the motor. Squirrel-cage motors are designed according to NEMA-type "letter designations" which describe the motor.

Table I lists three NEMA categories and their corresponding characteristics. The motor locked-rotor current has no direct relationship with motor torques, and the values of locked-rotor currents must be obtained from standard tables or directly from the motor manufacturer.



STARTING CURRENTS for squirrel-cage and synchronous motors are reduced with reduced-voltage or part-winding starters. **(FIGURE 1)**

NEC Code Letter	Limits for Cage Motors Kva per Hp Locked-Rotor
A	0 — 3.14
B	3.15— 3.54
C	3.55— 3.99
D	4 — 4.49
E	4.5 — 4.99
F	5 — 5.59
G	5.6 — 6.29
J	7.1 — 7.99
K	8.0 — 8.99
L	9.0 — 9.99
M	10.0 —11.19
N	11.2 —12.49
P	12.5 —13.99
R	14.0 —and up

TABLE II

Table II shows the range of starting kva as specified in the National Electrical Code. The code letters apply only to standard low voltage squirrel-cage induction motors up to 200 hp.

There is no definite correlation between the NEMA design letter and the NEC code letter. If the actual value of the motor-starting current cannot be obtained, an average value of 600 percent is usually assumed for squirrel-cage and synchronous motors. This value is usually close enough for use in applying standard equipment.

System stability upset

The starting of motors on full voltage can produce harmful effects if sufficient reserve kva is not available from the power system. The effects on the power system usually result in dips in line voltage. This may be produced by exceeding the feeder transformer capacity, excessive line loss, or a combination of both. In addition, starting currents can cause the system protective devices to open and interrupt service completely.

A dip in line voltage greatly affects the equipment connected to the system. Voltage dips of sufficient magnitude can cause synchronous motors to pull out of step, release holding circuits in motor starters and stop their motors, produce serious overheating to motors, and damage the motor controllers. Motor overheating is produced because of the longer accelerating time during which the motor winding must carry starting current, and because of higher running currents with motors running at greater percents of slip.

Motor starters are magnetically held in the running position and may drop out to stop the motor if the line

NEMA Code Letter	Syn. Speed, Rpm	Hp Range	% of Full-Load Torque		Slip	% of Full-Load Locked-Rotor Current	Application
			Locked-Rotor	Breakdown			
A	3600 1800 1200 900 720 600 514 450	1½-200 1 -200 ¾-200 ½-200 ½-200 ½-200 ½-200 ½-200	175-100 275-100 175-125 150-125 150-120 115 110 105	Design A Values Are In Excess of Those For Design B	Less Than 5%		Special High Breakdown Torque and High Locked-Rotor Current.
B	3600 1800 1200 900 720 600 514 450	1½-200 1 -200 ¾-200 ½-200 ½-200 ½-200 ½-200 ½-200	175-100 275-100 175-125 150-125 150-120 115 110 105	275-200 300-200 275-200 250-200 200 200 200 200	Less Than 5%	820-630 720-622 603-591	Standard Characteristics Suitable for Most Applications.
C	1800 1200 900	5 -200 3 -200 3 -200	250-200 250-200 250-200	200-190 225-190 200-190	Less Than 5%	820-630 720-622 603-591	Applications Requiring High Initial Torque to Start.
D	1800 1200 900	½-200 ½-200 ½-200	275 275 275	275 275 275	5% or More	820-630 720-622 603-591	High Torque and High Slip, for High Inertia Loads.
F	1800 1200	30 -200 30 -200	125 125	135 135	Less Than 5%		Low Locked-Rotor Current and Torque.

TABLE I — Characteristics of NEMA design motors

voltage should drop sufficiently. Motor controllers will usually open at approximately 70 percent of normal voltage or below. Such shutdowns often prove costly.

The minimum operating voltage permitted by the manufacturer's guarantee of motors is 10 percent less than rated nameplate voltage. The load characteristics of the motors cannot be obtained if the operating line voltage should fall below this point. The minimum voltage permitted for the operation of motor controllers is 15 percent below the nameplate rating. In some cases motors have been found to develop insufficient torque to accelerate their loads on Monday morning, but would start successfully on other mornings. The cause was usually found to be due to a low voltage condition produced by all industrial plants in an area attempting to start up their plants at exactly the same time. The 15 percent minimum should not be exceeded during the acceleration or during normal operation of motors.

Low voltage troubles can be relieved

While a low voltage condition might be corrected by additional transformer capacity or with synchronous condensers, other less costly methods should be explored first. Generally, voltage correction methods — switch capacitors, voltage regulators or load tap-changing transformers — are too slow to be effective in correcting low voltage conditions resulting from motor starting.

When adding motor loads to a distribution system, the normal full-load currents of the motors may not be a problem. However, the starting inrush of the motor may cause a serious voltage drop in the lines. If the line drop is excessive, the condition can be improved by increasing the cross-section area of the conductors, by altering the conduit runs or the spacing factor of the lines, and by other means. Figure 2 shows the voltage drop per ampere of current for various conductor sizes based on 12-inch spacing in air. These values vary greatly, depending upon conductor sizes, spacing, conduit, voltage, insulation, etc. Data covering the actual line condition should be obtained before any changes in the system are considered.

Frequently motor circuit lines are designed with a 1-volt drop allowed in the branches, with two-thirds of the remaining drop in the mains and one-third in the feeders. Most of the drop should be confined to the mains in order that a variation in the load on one motor of a group will affect the others as little as possible. Where motor circuits are fed by transformers, it is usually assumed that the voltage at the secondary side of the transformers remains practically constant, and therefore all of the allowable drop is apportioned to the secondary circuit.[1] When a group of motors is fed by a main and branches, the drop in the branches, if they are not too long, is frequently 1 volt or less, under normal working conditions, because the NEC requires that a branch conductor serving a motor be capable of safely carrying a current at least 25 percent greater than the normal full-load current of the motor.

This is a theoretical consideration, and the utilities' problem is to maintain the secondary voltage as near constant as practical.

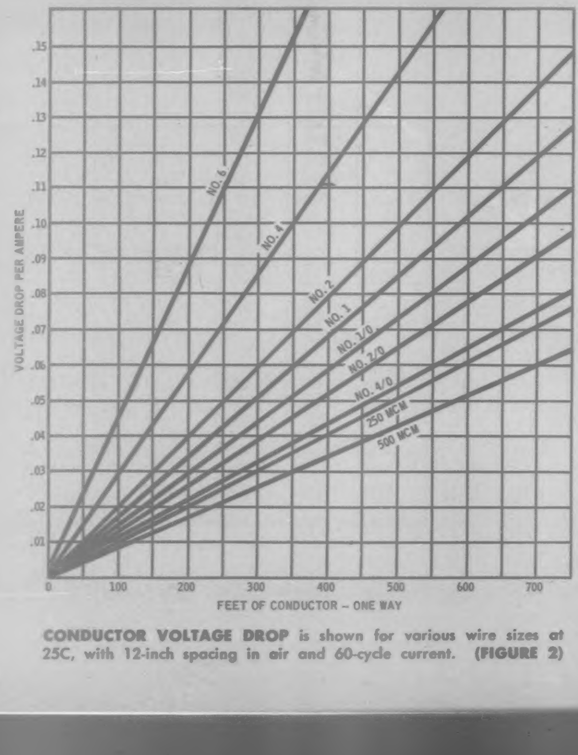
Selective starting

Low line voltages can be produced by attempting to start too many motors at one time or through an incorrect sequence. Motors should be started individually or in blocks of permissible size if it is necessary to avoid serious voltage drop. If large motors and small motors are to be started on a common power system, best results are obtained by starting the larger sizes first and the smaller sizes last. This sequence permits the larger motors to take ad-

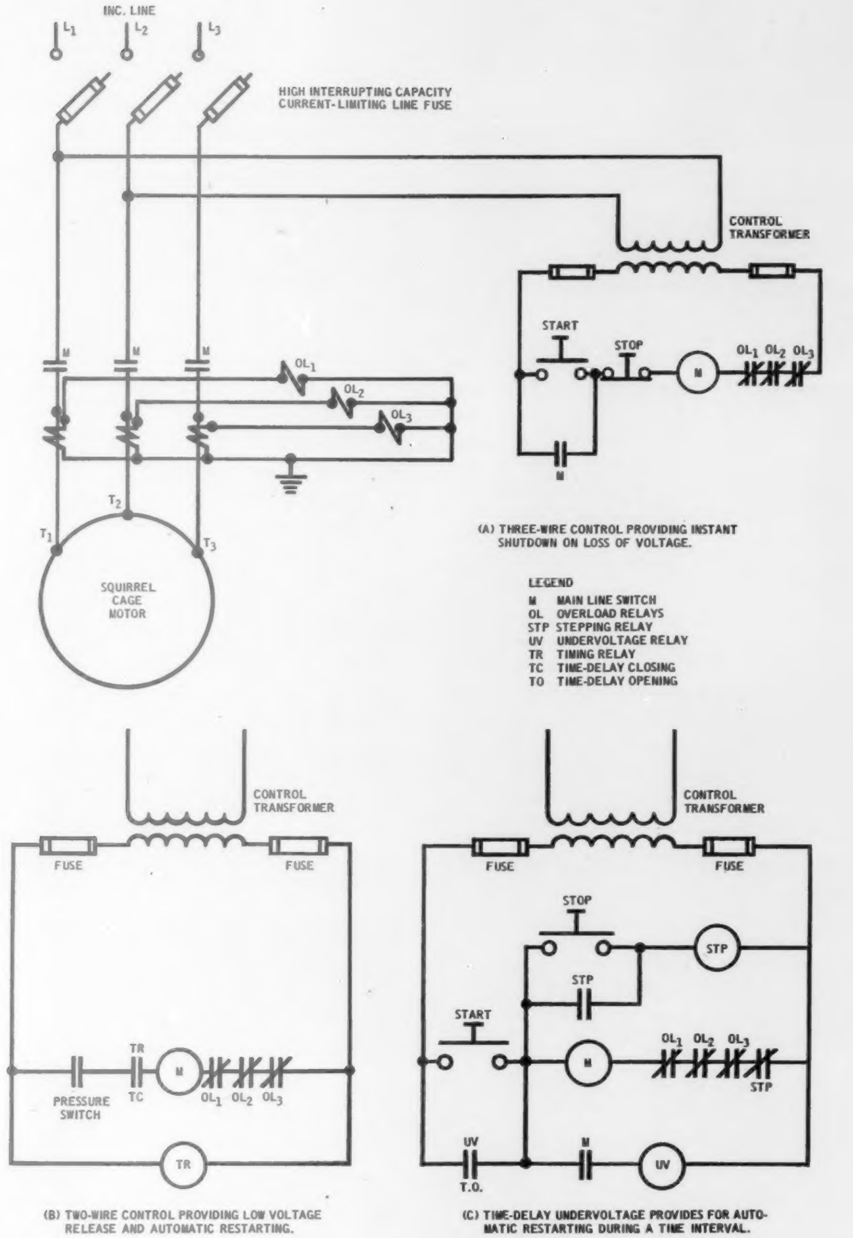
[1] From *Standard Handbook for Electrical Engineers.*

Hp	Locked-Rotor Current for Three-Phase, 60-Cycle, 220-Volt Motors (Amperes)	
	Designs B, C, and D	Design F
1 or Less	25/hp	...
1½	35	...
2	45	...
3	60	...
5	90	...
7½	120	...
10	150	...
15	220	...
20	290	...
25	365	...
30	435	270
40	580	360
50	725	450
60	870	540
75	1085	675
100	1450	900
125	1815	1125
150	2170	1350
200	2900	1800

TABLE III



CONDUCTOR VOLTAGE DROP is shown for various wire sizes at 25C, with 12-inch spacing in air and 60-cycle current. **(FIGURE 2)**



FULL-VOLTAGE STARTERS are provided with one of three basic control schemes. The selection is based on both the application and the power distribution system requirements. **(FIGURE 3)**

vantage of the full-line capacity. If synchronous motors are on the system with other types of ac motors, the synchronous motors should always be started first. Synchronous motors draw less kva from the system than other types and can supply reactive power to the system if allowed to run unloaded or overexcited.

Although systematic starting allows motors to be started successfully without an excessive line-voltage drop, the line must still be protected while the motors are running. When three-wire control circuits are used, as shown in Figure *3a*, a severe dip in line voltage or a momentary complete outage causes the control sealing circuits to be broken and the controller to drop out and stop the motor. This type of controller operation is called "low voltage protection" and does afford maximum protection to the system by not permitting all motors to accelerate back to full speed after being slowed down because of the voltage dip. The objection which many operators have to this arrangement is that all motors are lost from the line during the voltage dip and each must be restarted as on the original start.

In order to overcome this objection, circuits are available which permit dropout of the controllers on low voltage dips but allow them to restart automatically if normal voltage is restored within a preset time delay. This type of controller operation, called "time-delay undervoltage protection," is illustrated in Figure *3b*. The usual time delay can be set up to two seconds.

Time-delay undervoltage on controllers prevents some complete shutdowns, but its wide use should be viewed with caution. If used on all motor controllers on the system, restoration of voltage within the time-delay setting after a voltage dip would cause each motor to attempt to accelerate simultaneously, thus producing excessive currents. If the power system were not capable of the demand, the line voltage would fall and the currents would go still higher. As a result, the system would bog down completely and the motors would stall. The backup protection devices and starter overload devices would then be called upon to disconnect the system. A compromise is sometimes possible with the use of the time-delay undervoltage controllers. All the motors on a system can be given priority listing according to their operating importance. The high priority units can be equipped with time-delay undervoltage protection, with the time-delay settings set at varying intervals and with the most important unit having the longest time setting. The lower priority units would have only low voltage protection and would not restart automatically. The choice of arrangement depends upon the various sizes and types of motors, types of loads, system capacity, and must be determined for each individual system. Controllers can be sequence-interlocked so that upon the starting of one unit a second unit will be started automatically after a set time delay.

Demand devices, such as pressure, float, temperature switches, automatically start and stop motors as the demand requires. On severe voltage dips or complete voltage failures the motor controllers drop open to stop the motors even though the demand switch is closed. On restoration of full voltage all units will attempt to restart together. This has proven serious on several installations where a number of large pumps and compressors were automatically controlled. This operating hazard can be overcome simply by adding a time delay in the starting of each motor after the demand contact has closed. The time delays in the various units are staggered so that on restoration of voltage only one unit at a time will be started. Such a circuit is shown in Figure *3c*. Most motor controllers are furnished as standard with "low voltage protection," three-wire control from a momentary pushbutton station. Time-delay undervoltage protection should be used only on units where shutdowns on momentary voltage fluctuations cannot be tolerated. Time-delay undervoltage is available as a modification on high voltage controllers when required and is offered on low voltage controllers only on very special applications.

Many low voltage controllers are made for two-wire control with demand switches. The time-delay feature for staggered starting is not included in the base prices but can be obtained for an additional price in any high or low voltage controllers.

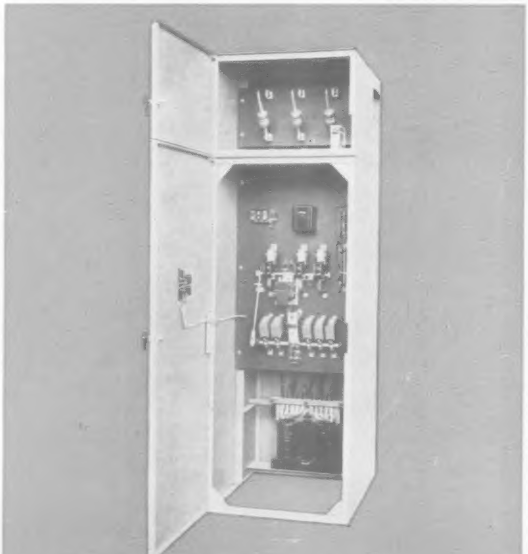
Starting current reduced

Another method of eliminating voltage problems during starting is to limit the motor starting kva. There are several methods of reducing starting inrush in squirrel-cage and synchronous motors. The types of starters are listed in the order of their importance:

Autotransformer	Part-Winding
Resistor	Wye-Delta
Reactor	

Where extremely high motor torque is required to break away a heavy machine load, the starting kva can be reduced through the use of a wound-rotor motor. These motors have the additional advantage of a high starting torque.

Editor's note: Each of these methods of starting motors will be covered in detail in Part II of this article.



USING AN AUTOTRANSFORMER to limit motor-starting kva, this 150-hp, 440-volt reduced-voltage fused starter is designed for a squirrel-cage motor application. **(FIGURE 4)**

STATOR FOR THE WORLD'S LARGEST MOTOR, this 34-ft diameter ring is nearly 8 feet high, weighs approximately 145 tons and required over 120,000 individual pieces of steel to form its laminations. Three cranes are transporting it to another area where coils will be fitted into the 360 slots of this 102,000-hp, 105.9-rpm motor stator. A shop assembly of the pump-turbine which will be driven by this motor rests on the erection floor beneath the stator.

Performance Characteristics of 150 C Rise Dry-Type TRANSFORMERS

ROOF TOP SUBSTATION is home of 300-kva, 150 rise transformer sealed in dry nitrogen. Since nitr gen is inert, its insulation qualities will not chang

by **W. M. TERRY**
Assistant Chief Engineer
Pittsburgh Works
Allis-Chalmers Mfg. Co.

Maintenance advantages of dry-type transformers have focused attention on new insulation methods and materials.

DURING the last few years the approach to the insulation classification of materials as used in electrical equipment has undergone a radical change. Since transformers are composite and complicated structures, as shown in Figure 1, temperature rises in the various parts of the structure vary widely. A typical temperature range is shown in Figure 2. No longer, in the majority of opinions, should the temperature classification of completed equipment necessarily be the same as the temperature classification of all the insulation materials in the unit.

NEMA has recently approved three temperature classifications for transformers — 55, 80, and 150 C continuous copper rises by resistance with respective hottest-spot copper rises of 65, 110, and 180 C. These rises are for equipment and do not specify the insulation materials to be used.

Insulation grouped by usage

In the transformer field, insulation applications break down into two major groups, as shown in Figure 1. The first grouping is major insulation from windings to grounded parts and between isolated windings; the second grouping is minor insulation between parts of the same winding.

Keep-back insulation to ground at the ends of windings, barrier structures between windings, winding and bus-bar lead supports to ground and bushings are considered major insulation. Minor insulation consists of turn-to-turn insulation, coil-to-coil insulation in disc windings, layer insulation in helical windings, and insulation between tap leads or other leads of the same winding.

In order to apply insulation properly, each proposed application must be checked for its electrical and mechanical functions. The keep-back insulation at the ends of the windings in a 150 C rise dry-type sealed unit serves both electrically and mechanically. It must provide for sufficient creepage surface to prevent flashover under all test and operating conditions. It must also withstand puncture and limit leakage current to prevent dielectric heating. Mechanically, the keep-back insulation must clamp the coils to resist vibration and abrasion between coils and turns during normal operation. The keep-back insulation must also have sufficient reserve mechanical strength to withstand the solenoidal action between windings and impact forces against the keep-back structure caused by severe short circuits.

In an open dry-type transformer not only are insulation creepage distances chosen to withstand initial test voltages but allowances are made for reasonable contamination of these surfaces, resulting in decreased flashover voltage. In contrast, the turn-to-turn insulation in a disc coil has the sole function of withstanding electrical puncture, since the mechanical stress is minute. Another example is the

spacers between disc coils of a high voltage winding. Electrically they provide insulation between coils, but mechanically need only to withstand clamping pressures, because the short circuit force between balanced coils is small.

Aging dictates type of insulation

In designing sealed 150 C rise dry-type units in power transformer sizes, the designer tries to use as much Class C material as practical, since thermal aging is not a factor in this class insulation. When conditions permit, windings and leads are supported on porcelain as major insulation. The dielectric strength of these Class C materials is equal to their flashover voltage in nitrogen and years of thermal aging have no deteriorating effect. Since the units are sealed, there is no contamination of flashover surfaces to lower dielectric strength.

Barriers between windings are made up of a combination of asbestos and Fiberglas impregnated with silicone resin. To provide for proper distribution of stress and for cooling, liberal ducts are used on each side of the solid barriers. The solid barriers themselves are designed to have a puncture value in excess of the total applied potential test for the insulation class of the winding. This strength plus that provided by the flashover voltage values of the spacers on each side of the barrier provides a large safety factor.

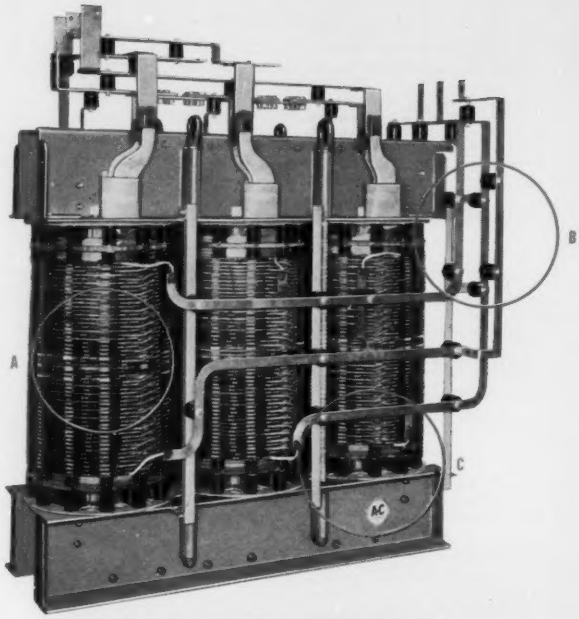
Turn-to-turn insulation consists primarily of double glass insulation impregnated with silicone resin. In portions of the coil adjacent to line terminals where stresses due to surges may be large, additional insulation is provided by silicone-treated Quinterra, a high intrinsic dielectric strength material regardless of thermal aging and even without the addition of silicone resin.

Coil-to-coil insulation and layer-to-layer insulation are provided by silicone-treated asbestos spacers or porcelain spacers, acting alone or in combination with sheet insulation of silicone-treated Quinterra, varnished Fiberglas cloth, or silicone-rubber treated glass cloth.

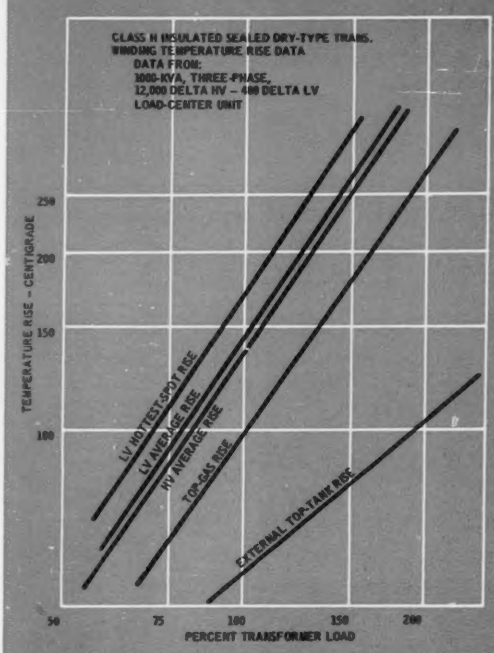
Leads and taps are insulated with silicone-rubber insulated cable or are taped with silicone-varnished glass cloth or Quinterra tape. Where terminal boards or tap boards are required, silicone glass laminate is used.

Solvents eliminated by baking

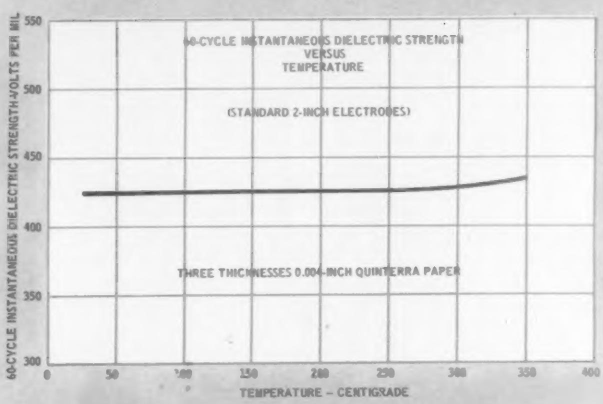
The final assembly is treated and impregnated with a pure silicone varnish and then given a solvent removal bake at 125 C, followed by a high temperature bake at 240 C, to thoroughly cure the resin. It is extremely important that all silicone materials are thoroughly cured and all solvent removed before the unit is sealed in its own tank for service. If the materials are not cured completely, additional solvent products will be driven off under load. Since they cannot escape, they remain indefinitely in the tank and will react with all insulation materials affected by the solvents. Where leads are taped and brushed with silicone resin after the complete core and coil assembly has been treated and cured, care is taken to make certain that these newly treated areas are also thoroughly cured. A very small amount of solvent captive in the tank can do a lot of damage.



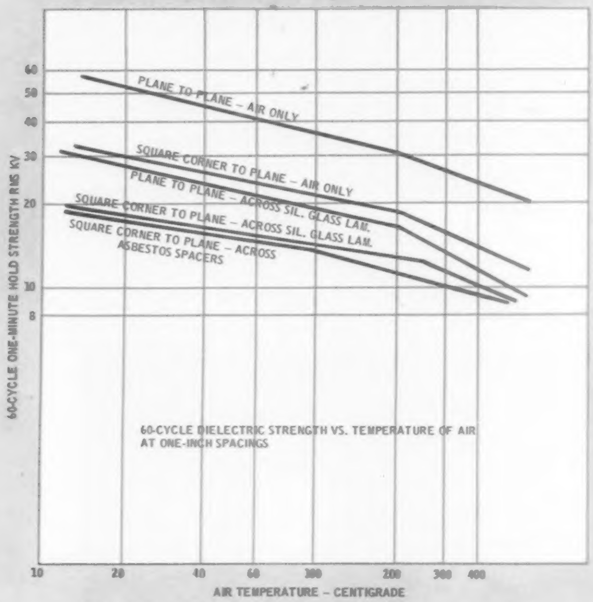
TRANSFORMER INSULATION GROUPING is keyed to mechanical and electrical stresses. This 1000-kva, 150 C rise, 4160-delta—480Y-volt core and coil will be used in hermetically sealed load-center substation unit. **(FIG. 1)** (A) Minor insulation. (B) and (C) Major insulation.



TEMPERATURE RISE in various parts of a transformer differs widely. Hence the temperature classification of the insulation is not dictated by the overall temperature classification of the transformer. **(FIGURE 2)**



INSULATION STRENGTH of solid Quinterra asbestos paper is relatively constant in the normal operating temperature range of transformers rated 150 C rise. (FIG. 3)



AIR DIELECTRIC STRENGTH decreases as the temperature increases. The breakdown voltage of nitrogen is about the same as air under these conditions. (FIG. 4)

Silicones create problems

Silicone resins present several problems in their application, one of which involves the use of silicone-varnished glass cloth as insulation. Its total dielectric strength depends entirely on the integrity of its resin film. The glass serves only as a carrier except for the spacing provided by its thickness. The abrasion resistance of this material in normal layer thicknesses is poor. Furthermore, what may be 1000-volt-per-mil material as received in flat sheet form quickly reduces to air breakdown under average handling during coil winding. For these reasons silicone-treated asbestos paper, which has an intrinsic dielectric strength not dependent entirely on the integrity of a varnish film, has been preferred. Its chief drawback is its limited mechanical strength.

Another problem common to both silicone resins and rubbers is their low resistance to solvents normally used in silicone varnishes, such as toluene and xylol. This problem exists even when the silicones are in a cured state.

As an example, a sheet of silicone-varnished Fiberglas cloth or silicone rubber may be used as layer insulation. After the winding is complete, spring-backed compressive forces exist between layers due to winding tensions. If the layer insulation is not thoroughly cured prior to the time the winding is impregnated, the solvents in the impregnating varnish will attack and soften the layer insulation. This weakening may allow the winding layers to push together, resulting in decreased dielectric strength between layers.

Cost of silicones is high

As insulation materials are priced, silicones are high in relation to organic materials. However, as their use has increased, economies have been realized in their manufacture. In 1945, for example, basic demethyl silicone fluid, produced commercially, was $5.70 a pound and has since dropped to approximately $3.80 a pound, a 33 percent decrease. However, 150 C rise dry-type insulation, as purchased ready for use, has remained relatively stable in

Comparison of Transformer Weights and Dimensions

	1000-Kva, Three-Phase Transformer With Tap Changer			1000-Kva, Three-Phase Transformer With Tap Changer			1000-Kva, Three-Phase Transfor[m] With Tap Changer			500-Kv[a]
	Sealed Dry Type	Open Dry Type	Oil Filled	Sealed Dry Type	Open Dry Type	Askarel Liquid Filled	Sealed Dry Type	Open Dry Type	Askar[el] Liqui[d] Fille[d]	Seale[d] Dry Ty[pe]
Impedance	5.5	5.5	5.5	7.0	5.4	5.4	5.7	5.5	7.0	5.0
Volts, HV	12,000△	13,800△	12,000△	12,000△	13,200△	13,200△	4160△	4160△	4160	4160
Volts, LV	4160Y	480△	480Y	480△	4800△	480△	480△	480△	480	480
Weight of core and coils	12,329	10,090	6011	7731	8596	4783	7815	7085	414	390
Total weight	27,800	16,000	16,500	17,900	13,650	15,870	14,970	11,800	15,30	860
Length (inches)	120	104	70	97¾	104	66	87¾	90	68	69
Width (inches)	68	54	57¾	55	54	53¾	45½	54	53	46
Case height (inches)	112⅛	98½	101	111⅝	98½	77⅜	103⅝	98½	77	73
Total height (inches)	115½	100	111⅛	115	100	83⅞	106⅜	100	83	76

price, since decreases in basic material costs have been offset by increases in labor and other costs.

Straight silicone varnish costs approximately $14.00 a gallon, compared to $3.50 a gallon for good phenolic organic varnish. Silicone glass laminate costs $5.00 to $7.00 a pound, while phenolic laminates cost $1.00 to $2.00 a pound.

A 1000-kva sealed dry-type transformer requires approximately 30 gallons of 50 percent solids varnish for impregnation. Hence, the silicone varnish cost alone is approximately $400.00 per unit.

Increased use of silicone rubbers to replace silicone-resin coated Fiberglas cloth as layer insulation is seen as a definite trend. Modern silicone rubber has many desirable properties and does not resemble the silicone rubbers originally produced. Its advantages are as follows:

a. Lower first cost.

b. Excellent corona resistance.

c. Retained dielectric strength under tension.

d. Good thermal aging properties.

e. Excellent flexibility and formability.

As wire insulation, the new silicone enamels are beginning to show promise. Up to the present time, double-glass covered wire, silicone treated, has been used. Recent heat shock tests on round silicone-enameled wire indicate greatly improved performance over earlier enamels, which were very poor in this respect.

For magnet wire and layer insulation, combinations of silicone-treated Quinterra and open-mesh glass threads are now being considered. The result of this combination is a predominantly Class C structure with good intrinsic dielectric strength and fair mechanical strength. It has been applied successfully on rectangular magnet wire, and has been proved in tests, both initially and after thermal aging periods.

Aging varies with temperature

The insulation strength of solid Quinterra asbestos paper insulation is shown in Figure 3. Between room temperature and 350 C little variation in breakdown voltage is evident. However, the 60-cycle dielectric breakdown voltage for air does decrease with increasing air temperature in both uniform fields represented by plane-to-plane data and nonuniform fields represented by square corner-to-plane data, as shown in Figure 4. Incidentally, the breakdown voltage in air is approximately equal to the breakdown voltage in nitrogen. Figure 5 shows a typical sealed dry-type distribution transformer.

Between room temperature and 100 C the dielectric strength of air in both uniform and nonuniform fields decreases approximately 27 to 30 percent. Between 100 and 200 C the dielectric strength of air in both uniform and nonuniform fields decreases 18 to 20 percent.

The interposition of a high dielectric constant material, such as silicone glass laminate or asbestos, decreases the dielectric strength of the uniform field approximately 47 percent and of the nonuniform field approximately 38 percent. The decrease is less for the nonuniform field condition because the gradient changes are less.

To demonstrate the wide differences in insulation life that can be obtained, thermal aging data for two different sets of test conditions are shown in Figure 6. The curve on the left is for 0.010-inch silicone-rubber coated glass cloth hung in sheet form in an inert gas sealed chamber and aged. At periodic intervals sheets are removed, cooled to room temperature, bent over a ⅛-inch diameter mandrel and tested between the mandrel and a 2-inch plane electrode. This is a dynamic test because the dielectric strength is measured after mechanical flexing. The failure point is determined when the dielectric strength decreases to 50 percent of initial strength. In addition, the total dielectric strength depends on the integrity of the silicone-rubber film while bent around the ⅛-inch diameter mandrel. This curve demonstrates the excellent life characteristics of silicone rubber under severe test.

Insulation life at any temperature may be extrapolated by plotting the log of the 50 percent strength points in hours against the reciprocal absolute temperature scale. Based on the use of silicone rubber in 150 C rise sealed

500-Kva, Three-Phase Transformer Without Tap Changer		
Sealed Dry Type	Open Dry Type	Askarel Liquid Filled
5.0	5.0	6.9
4160△	4160△	2400△
480△	240 x 480△	240△
3903	4311	3045
8600	8300	10,300
69	78	60
46	54	41⅝
73	98½	76½
76	102¾	83

WINDINGS AND INSULATION in this 30-kva distribution transformer at a southern power company are protected against air contaminants with totally enclosed construction. **(FIGURE 5)**

transformers, the life at 210 C — the maximum hottest-spot temperature — would be approximately 60,000 hours or 6.8 years.

By comparison, the two curves on the right in Figure 6 are for silicone-resin treated Quinterra aged in air and in nitrogen under static conditions. The static condition is typical of insulation between rectangular magnet wire conductors clamped together, simulating turn-to-turn insulation in a transformer coil. Based on the criteria of aging time to 50 percent dielectric strength, this combination has a life of 40,000 hours in nitrogen at 300 C. The wide differences between the silicone-rubber curve in nitrogen and the silicone-treated Quinterra in nitrogen are the result of two factors. The first factor shows up in a comparison of the dynamic bend test for the rubber with the static test for the Quinterra, which is not mechanically disturbed except for temperature expansions and contractions when the samples are removed from the oven and allowed to cool to room temperature before electrical stress is applied. Secondly, the silicone-treated Quinterra combination is predominantly Class C insulation, with the Quinterra having a high intrinsic dielectric strength.

A small difference exists between the two curves of the silicone-treated Quinterra aged in air and in nitrogen because the conductors are clamped and sealed together by silicone varnish, which protects all but the edges from the effects of oxidation.

These curves clearly show that temperature classifications of equipment are justified and that it is best to leave to the designer the choice of materials for a specific application. Here are shown two widely different life curves of two materials both of which are considered 150 C rise insulation. It is therefore incorrect to assume that a material with an insulation life of so many hours under one type of test can be used anywhere in the transformer.

Sealed units compared

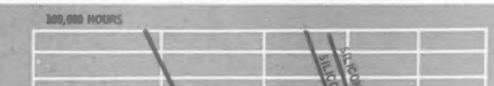
The 150 C rise sealed dry-type transformers are designed to have the same electrical performance characteristics as Class B ventilated 80 C rise transformers. Core losses, total losses, and impedance values are identical.

Thermal performance data shown in Figure 1 are taken from a typical 1000-kva, 12,000-480-volt load-center unit. Tests show that the temperature rise of the HV winding varies as the 1.6 power of the load, the LV temperature rise varies as the 1.6 power of the load, and the hottest-spot rise varies as the winding temperature rise.

The top-gas temperature rise varies directly with the winding temperature rise. Hence, this temperature may be used as a load indication, using a thermometer with bulb extending into the top gas. The external hottest-spot tank rise varies as the 0.9 power of the load.

In all sealed dry-type units all windings have generous open ducts to provide for low hottest-spot rises. The 180 C hottest-spot copper rise allowed for 150 C average winding rise equipment appears from test data to be entirely in line.

Figure 7 shows data taken on the same 1000-kva load-center unit with forced-air applications. The optimum fan arrangement, shown schematically, consisted of four 1800-cfm fans directed at a center point on the tank approximately two-thirds of the way up from the base. With this arrangement approximately 12 percent increase in load could be carried with the same winding temperature rises as for self-cooled. Based on this test and other tests on units ranging in size from 300 kva to 1500 kva, it does not seem feasible to utilize external forced-air cooling on sealed dry-type units.



THERMAL AGING RATES for insulation are result of more factors than temperature alone, and can be predicted only if all the operating conditions of the insulation are known. (FIGURE 6)

EXTERNAL FORCED-AIR COOLING is not used on the sealed dry-type transformers because only 12 percent load capacity is gained even with optimum fan positioning. This gain in capacity is substantially less than would be obtained with either liquid-filled type or the open dry-type units. (FIGURE 7)

Sealed construction protects insulation

Based on all field data, the sealed 150 C rise insulated dry-type transformer has proved to be entirely dependable and reliable. It is fire-proof and explosion-proof, and being hermetically sealed no dirt or contaminants can enter. Insulation clearances and creepage surfaces cannot be affected. The nitrogen gas is inert and its electrical properties do not change.

Maintenance of a sealed dry-type transformer is eliminated except for external cleaning and painting of the case and an occasional inspection of the pressure gauge to check for gas leaks. Even if a leak should occur — which in unlikely, as the leaks could occur only at gasketed hand holes and bushings — the unit would operate satisfactorily for long periods of time.

No special precautions need be taken to put the transformer in service other than to make sure the unit is holding gas pressure. The unit can be de-energized for long periods of time without any dryout required to put it back on the line. Being entirely sealed, the unit needs no protection against possible flooding or spray conditions from breaks in water or steam mains.

The sealed dry-type unit requires no vault and may be located wherever it is most convenient — in basements, on overhead grilles, or on roofs. The totally enclosed distribution unit is ideal for plant locations where dust, dirt, airborne contaminants, or lint are factors. It can be installed indoors or outdoors.

Low maintenance offsets extra cost

Using base prices, sealed dry-type network and load-center units cost initially 20 percent more than Askarel liquid-filled units. In many applications, this higher first cost is offset by the application advantages and reduced maintenance throughout the life of the unit.

Table I shows a comparison of losses and annual costs of 55 C rise liquid-filled transformers, 80 C rise Class B ventilated dry-type units, and 150 C rise sealed dry-type transformers at various assumed load factors. All load factors were chosen with the unit operating part of the time at full load on the assumption that full transformer nameplate capacity was required for some portion of the time.

Core losses and total losses used are for a 1000-kva, 4160 or 4800 to 480 or 600-volt transformer of each class. For each load factor the actual transformer losses, based on temperature rise of the unit at each load, were computed, totaled, and compared to the actual losses of the liquid-filled unit at a load factor of 100 percent. Each transformer is assumed to have winding rises at full load equal to the maximum for its temperature class. The annual difference in operating costs is computed at a cost of one cent per kilowatt-hour.

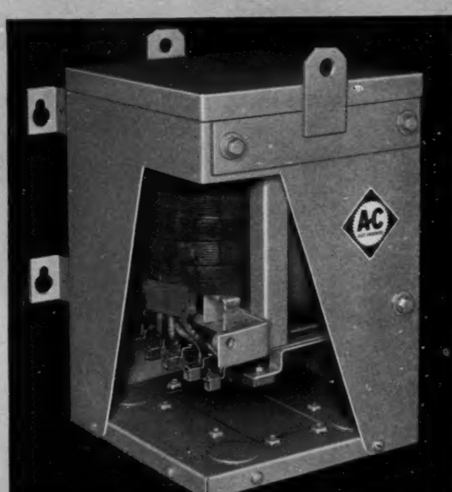
The small differences occur in the ventilated and sealed dry-type as compared to liquid-filled units because the 75 C guaranteed losses for open dry-type and sealed dry-type units are lower by approximately 10 percent on a total loss basis. The open dry-type and sealed dry-type ratio of losses is 2.1, as compared to a ratio of losses of 3.0 for the liquid-filled unit. Core loss of the dry-type units is about 25 percent higher than for the liquid filled.

TABLE I
Comparison of Losses and Annual Cost Differences at Different Load Factors for 1000-Kva, Three-Phase Unit HV — 4160 or 4800 Volts, LV — 480 or 600 Volts

Percent Load Factor		Temperature Class 55 C	80 C	150 C
100 (Full load continuous)	Percent Loss	100	94	106
	Dollars Cost	—	65.60	67.80
87.5 (0.5 time at full load + 0.5 time at 75% load)	Percent Loss	100	96	106
	Dollars Cost	—	39.40	50.70
75 (0.5 time at full load + 0.5 time at 50% load)	Percent Loss	100	97	106.5
	Dollars Cost	—	22.30	53.10
62.5 (0.25 time at full load + 0.25 time at 75% load + 0.25 time at 50% load + 0.25 time at 25% load)	Percent Loss	100	99.5	106.7
	Dollars Cost	—	3.94	46.10
50 (0.25 time at full load + 0.25 time at 50% load + 0.5 time at 25% load)	Percent Loss	100	102	108.5
	Dollars Cost	—	9.90	48.50
43.75 (0.25 time at full load + 0.75 time at 25% load)	Percent Loss	100	103	109
	Dollars Cost	—	15.10	49.30

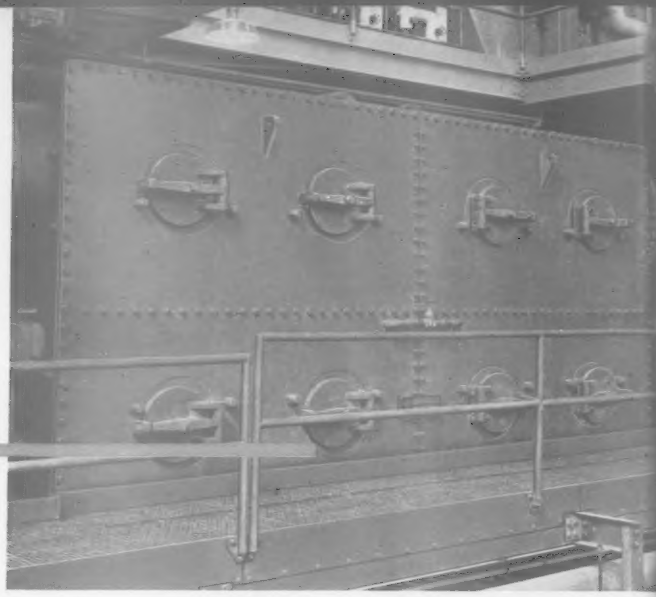
NOTES:
Percent loss based on 55 C rise liquid filled as 100 percent.
Cost equals annual kwhr cost difference in dollars at one cent per kwhr.

PORTABLE MINE SERVICE calls for compact, moisture-proof, dust-tight and explosion-resistant transformer construction. This sealed dry-type 150 C rise, 112½-kva, three-phase, 60 cycle, 2400-240-volt unit fills the need in Southwest coal mine. **(FIGURE 8)**



TOTALLY ENCLOSED dry-type distribution transformers are now used in wide variety of applications. Construction of 5-kva, 150 C rise, 480-120/240-volt unit is shown. **(FIG. 9)**

Selecting STEAM SURFACE CONDENSERS



EQUIPPED with rectangular steel water boxes of the divided type, this two-pass condenser has 50,000 sq ft of surface.

by W. E. ELLINGEN
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Allis-Chalmers Mfg. Co.

Economics, engineering, and natural conditions at the power plant site influence condenser design selection.

THE GROWING DEMAND for higher central station efficiencies has focused attention on ever higher steam pressures and temperatures at the turbine throttle. However, if the greatest possible efficiency is to be obtained from a steam turbine-generator unit, exhaust steam conditions and the surface condenser that determines them must be carefully considered.

By reducing steam to condensate and producing a vacuum at the turbine exhaust, a steam surface condenser extends the range of expansion in the steam cycle and makes more work possible per pound of turbine throttle steam. This in turn lowers the turbine water rate and reduces the size of steam-generating equipment. In addition, the steam condenser returns heated distilled water to the system and keeps boiler feed-water make-up requirements to a minimum.

How big should a condenser be

While a condenser that will give the highest possible vacuum may seem to be the most desirable for any application, economic factors which must be considered when specifying the size and type of a condenser usually modify this objective.

The theoretically perfect condenser would allow exhaust steam to expand until its temperature equaled the circulating-water outlet temperature. To accomplish this a condenser would have to be infinitely large and would have infinite cooling-water requirements. Consequently, in actual practice it has been found that the practical limit for this temperature differential, called terminal temperature difference, is about 5 F for a two-pass condenser and 10 F for a single-pass unit. Initial investment, pumping charges, and space requirements usually cannot justify a condenser with smaller terminal differences than these.

Most surface condensers are designed for either one or two circulating-water passes, as indicated in Figure 1. The difference between circulating-water inlet temperature and exhaust steam temperature, called initial temperature difference, should generally be about 20 F, regardless of whether a single-pass or two-pass condenser is being considered. See Figure 2. Within the range of accepted practice, the following circulating-water inlet temperatures and turbine-exhaust pressures are combined in condenser design.

Circulating-water inlet temperature, degrees F	Turbine-exhaust pressure, in. Hg abs
55-60	1.0
70	1.5
80	2.0
85	2.5
95	3.0

Calculations based on any pair of these conditions will result in condensers of approximately the same size.

Single-pass vs. two-pass condenser

Since a two-pass condenser will handle eight pounds per hour of steam per square foot of surface under average conditions, and the single-pass condenser will handle ten pounds per hour, per foot of surface, the single-pass condenser will probably make the best installation where space is a limiting factor. However, selection of the single-pass condenser because its space requirement is only 80 percent

ONE OF TWO 115,000-sq ft single-pass condensers which will be shipped to Detroit Edison Company for use with the No. 1 and No. 2 generating units at their River Rouge Station, is shown on the preceding pages in the process of shop assembly.

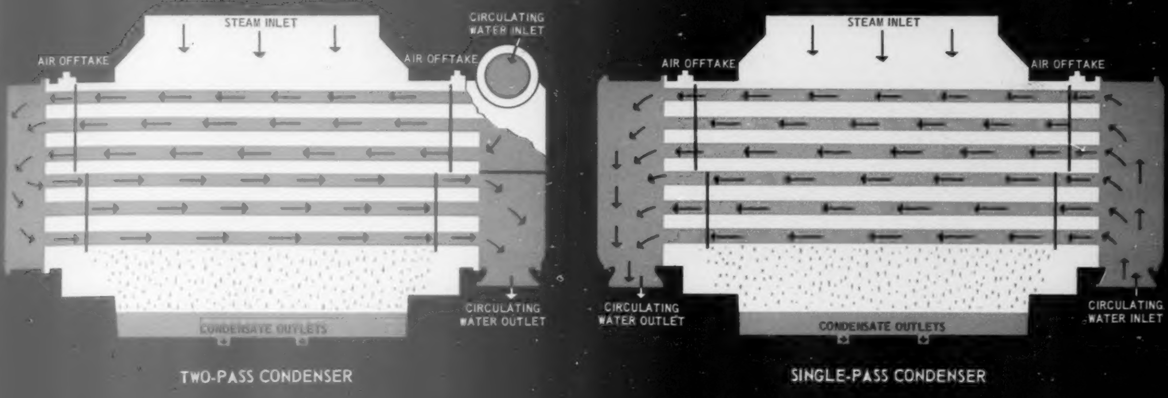


FIGURE 1

that of the two-pass condenser is tempered by the relative circulating-water requirements of the two units.

A comparison of Figures 3 and 4 indicates that a single-pass condenser will require approximately 50 percent more circulating water than a two-pass condenser for a given steam flow. Therefore, to take advantage of the smaller space requirement of the single-pass condenser, an adequate supply of cooling water must be available throughout the entire year.

Where the external head of a circulating-water system is great because of lengthy conduit or a cooling tower head, a two-pass condenser probably will be chosen. Even though the friction head of a two-pass condenser is greater than that of a single-pass condenser, a saving in brake horsepower will probably result because a smaller amount of water is circulated. On the other hand, where the external head of a system is less than condenser friction, a single-pass condenser usually will result in a brake-horsepower saving.

Other considerations in determining the condenser design to be used are cost of water conduit, basement depth requirements and existing units in the station which may impose design limitations.

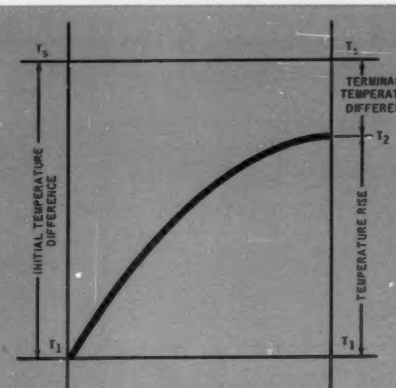
Variables affect condenser size

In addition to the factors affecting the choice of condenser design, factors influencing condenser surface area should also be considered. The effects of turbine-exhaust pressure, condenser-tube cleanliness, circulating-water velocity and inlet temperature on condenser size can best be evaluated on the basis of the following typical set of conditions:

Circulating-water inlet temperature............80 F
Turbine-exhaust pressure ....2.0 in. Hg abs
Circulating-water velocity ....7.0 fps
Condenser-tube cleanliness factor.........85 percent

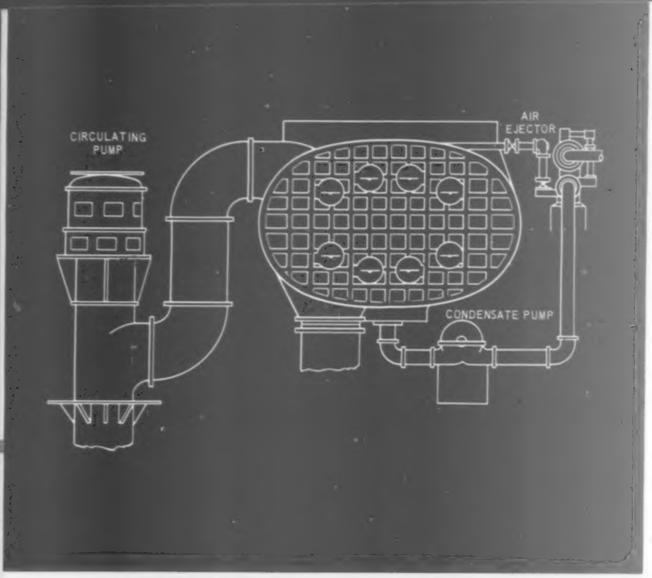
Changing any one of these conditions while keeping the others constant will result in the following changes in surface area and circulating-water requirements:

1. For each degree Fahrenheit increase in circulating-water inlet temperature, surface and circulating-water requirements will increase 5 percent.
2. For each reduction of 0.1-in. Hg abs pressure at the turbine exhaust, the surface and circulating-water requirements will increase 9 percent.
3. For each 0.1-fps change in circulating-water velocity, the surface required will change 0.85 percent and the circulating water 0.45 percent. Increasing the velocity will decrease the surface and increase the circulating water. Decreasing the velocity will have the opposite effect.
4. Increasing the tube-cleanliness factor 5 percent will decrease surface and circulating-water requirements 3.5 percent.



T_s = temperature of steam.
T_1 = temperature of inlet circulating water.
T_2 = temperature of outlet circulating water.

INITIAL TEMPERATURE DIFFERENCE is generally about 20 F regardless of condenser design, while circulating-water temperature rise is approximately 10 F for most single-pass condenser installations, 15 F for the average two-pass condenser installation. **(FIGURE 2)**



RELATIVE LOCATION of equipment usually furnished with a steam surface condenser is indicated in this sketch.

In the final plant design, a compromise between first cost, condenser vacuum, pumping charges and connected load charges, which these variables will determine, can result in the best design and a condenser that will utilize the cold end of the steam cycle most efficiently.

Associated equipment must be considered

Several additional pieces of equipment required in the condensing cycle are usually furnished with a condenser. These include:

1. Air-removal equipment.
2. Circulating pumps and their driving motors.
3. Condensate pumps and their driving motors.
4. Spring supports with jacks or an expansion joint.

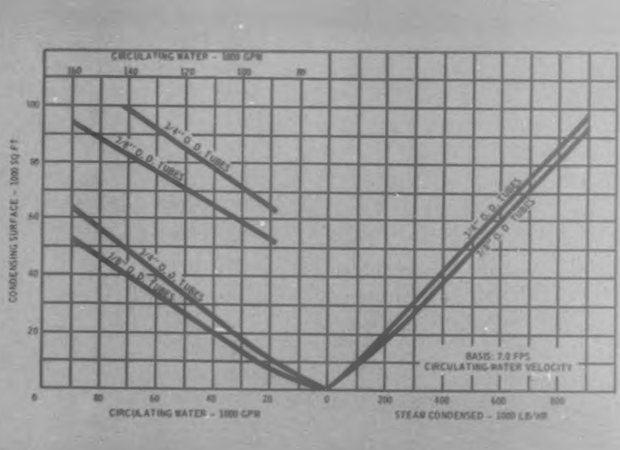
These items when considered as a part of the condenser installation, become an economic factor influencing the selection of either the single or two-pass design. The curves shown in Figure 5 therefore include the following auxiliary equipment: Air-removal equipment consisting of one two-stage, twin-element steam-jet air ejector; two half-capacity, 50-foot head, horizontal circulating-water pumps with induction drive motors; and two full-capacity, 225-foot head, horizontal condensate pumps also with induction drive motors.

Condenser tubes have not been included with the items of Figure 5 because it is now accepted practice to consider tubes as a separate item. For this reason, a separate curve, Figure 6, has been included to show the relative expenditure for condenser tubes, depending on condenser size, with applicable correction factors for the various commonly used tube materials. The practice of obtaining tubes from a separate source and installing them in the field is followed almost universally with condensers larger than 14,000 sq ft. This practice is also becoming more common with condensers 14,000 sq ft and smaller, which are factory tubed. Tubes for factory-tubed condensers are forwarded to the condenser manufacturer for installation.

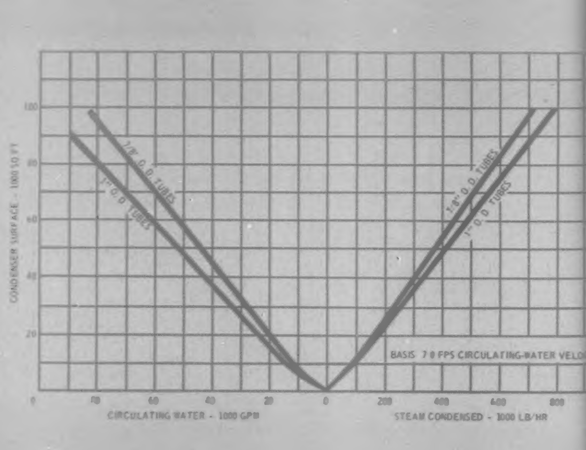
Equipment modifications influence initial investment

Figures 7 and 8 have been prepared to secure a more accurate comparison between a single-pass and a two-pass condenser installation. They provide additional information which modifies the quantities indicated by Figure 5. Figure 7 allows adjustment for either axial or mixed-flow circulating pumps. Axial-flow pumps generally have a maximum head of 25 feet, while heads on mixed-flow and centrifugal types can vary considerably. For any change in head from that indicated on the curves, pump costs will increase approximately 1 percent for each foot.

Additional adjustments may also be required. Vertical pumps having a 16-foot column length from suction bell to motor-support flange were assumed. Columns longer than this will increase cost approximately 2 percent for each additional foot of column. If non-removable vertical



SINGLE-PASS condenser selection chart. **(FIGURE 3)**



TWO-PASS condenser selection chart. **(FIGURE 4)**

circulating pumps are desired, then a deduction of 15 percent can be assumed for axial-flow types, and 20 percent for mixed-flow types.

The type and head of the condensate pumps also will affect condenser cost. In Figure 5, two full-capacity horizontal condensate pumps with a rating of 125 percent of the steam being condensed and a total dynamic head of 225 feet were assumed. Corrections for variations in type and head requirements of the condensate pumps can be made by reference to Figure 8.

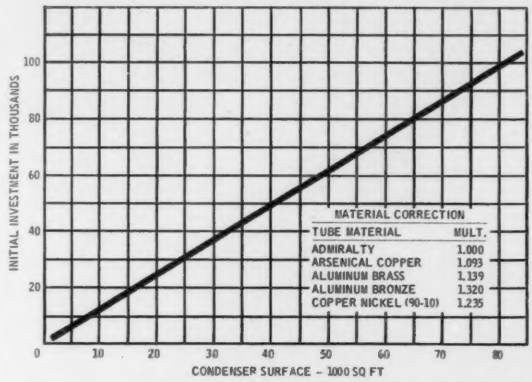
Other auxiliaries that are frequently furnished with a steam surface condenser are primers, air meters, hot-well liquid-level control valves, air piping, condensate piping, storage hot wells and extended condenser necks. Addition of these auxiliaries will increase the average condensing unit expenditure about 5 percent.

Within the condenser itself, differences in tube diameter and length are more or less compensating. Longer tubes will require less water but more surface, so the increased surface required will be offset by reduced circulating-water needs.

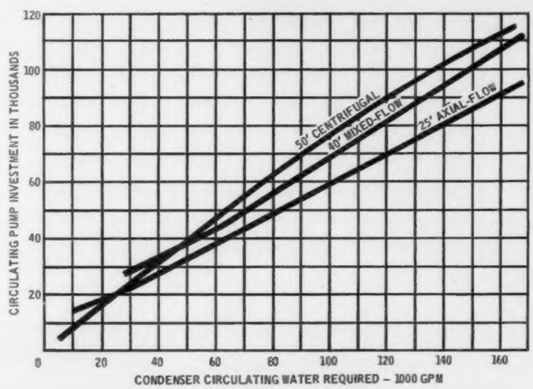
Economic comparison of single and two-pass units

The relative size and expenditure for a single-pass as compared to a two-pass condenser can best be determined on the basis of a specific application. Consider the following typical set of known values:

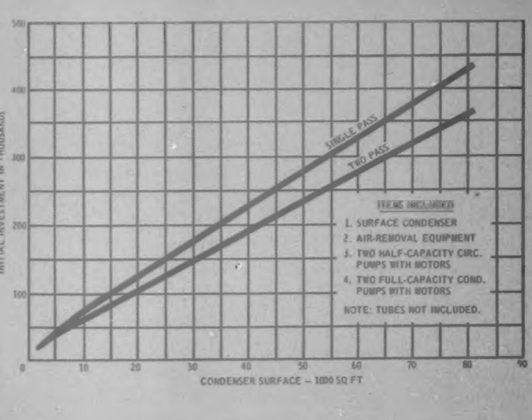
Steam to be condensed	600,000 lb per hour
Condenser tube material	Aluminum Brass
Condenser tube diameter	⅞ inch
Circulating pump type	vertical 16-foot column
Condensate pumps required	3 half-capacity vertical
Condensate head	600 feet
Total pumping head, single-pass	22 feet
Total pumping head, two-pass	34 feet



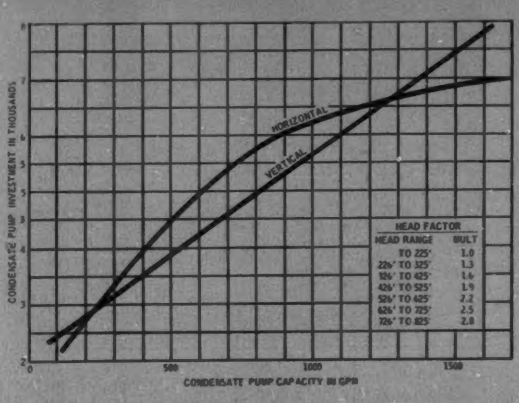
CONDENSER TUBES are an investment factor which must be added to data from Figure 5 in making the comparison. **(FIGURE 6)**



A CHANGE IN TYPE specified for the two half-capacity motor-driven circulating-water pumps will modify the cost data from Figure 5 by amounts obtained by interpolation from this chart. **(FIGURE 7)**



COST COMPARISON of single and two-pass condensers. **(FIGURE 5)**



COMPARATIVE COSTS of condensate pumps. **(FIGURE 8)**

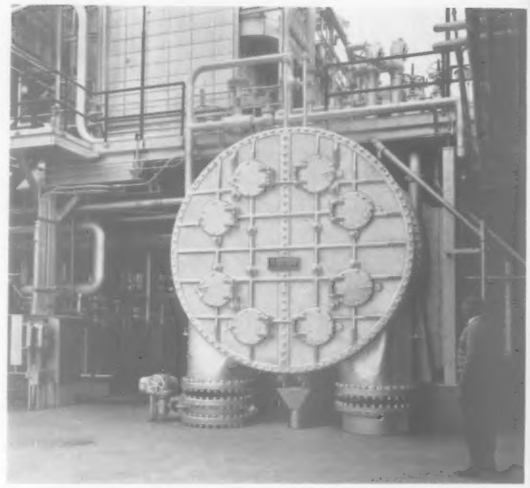
For preliminary purposes it is satisfactory to assume 7.0 fps circulating-water velocity.

For a single-pass condenser Figure 3 indicates the surface and circulating-water requirements are 60,000 sq ft and 102,000 gpm, respectively. Similarly, Figure 4 indicates a two-pass condenser will require 85,000 sq ft of surface and 73,000 gpm of circulating water.

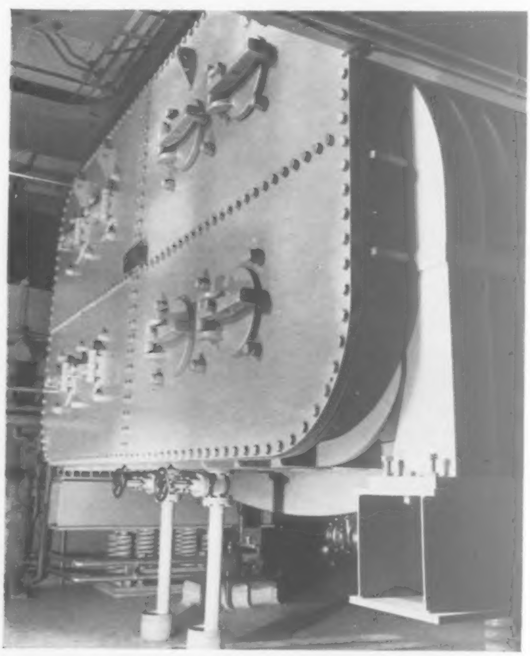
By the use of Figures 5, 6, 7, and 8, and making necessary corrections for tube material, pump type and head for both circulating and condensate pumps, totals of 432,750 and 523,350 are obtained for the single and two-pass condensers, respectively. From this comparison, it is quite evident that the cost of a condenser installation to do a specific job can vary considerably.

Although initial steam conditions can be evaluated and specified, maximum vacuum is limited by natural conditions at the power plant site. Neither the cleanliness factor nor the temperature of circulating water can be controlled. These two variables, together with the maximum and minimum water velocities they establish, place definite limitations on condenser vacuum. Despite these limitations, there is much that can be done to assure economies both in operation and initial investment.

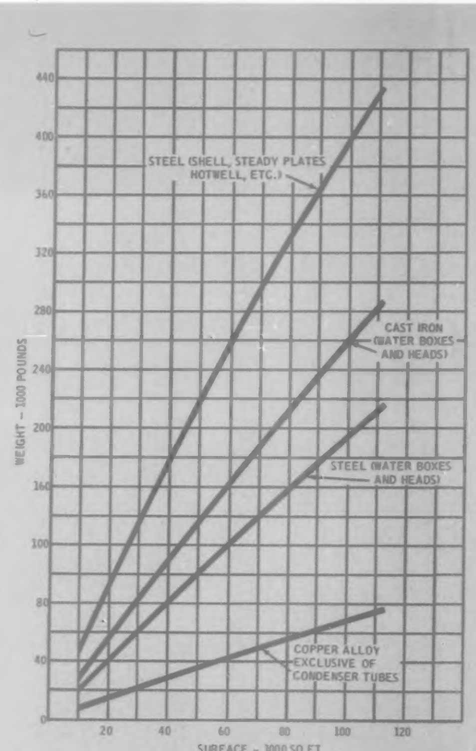
If maximum efficiency is to be obtained from the steam cycle, the condenser which determines the extent of steam expansion warrants serious consideration.



ONE OF THE TWO shells forming a twin 55,000-sq ft condenser outdoor installation at a south-central utility is shown.

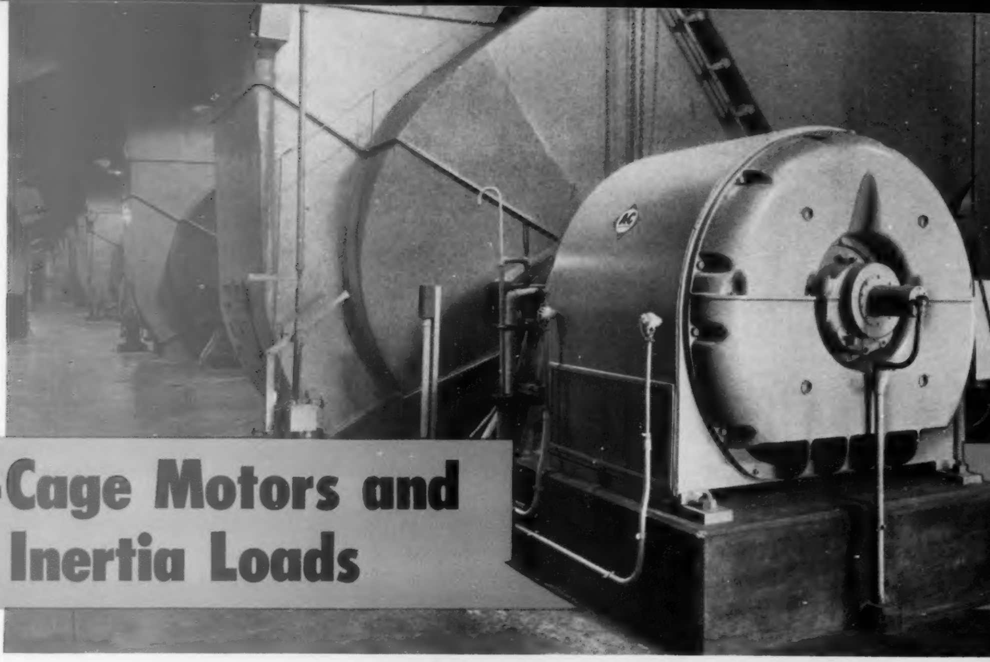


SHOWN FROM THE RETURN WATER BOX END, this 60,000-sq ft two-pass condenser is installed in a southern utility power plant.



AVERAGE WEIGHTS of the different components comprising a surface condenser can be determined from this chart. Summation of component material weights, plus 2.18 lb per sq ft for tube weight, will give the approximate total weight for the condenser being considered. **(FIGURE 9)**

Squirrel-Cage Motors and High Inertia Loads



IMPOSING A LOAD Wk^2 of 26,000 lb-ft^2 each, these induced draft fans are driven by 800-hp, 590-rpm cage motors. **(FIG. 1)**

by **G. BYBERG**
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New table indicates maximum loads standard cage motors can accelerate.

WHEN applying large squirrel-cage motors to high inertia loads, it is often difficult to determine whether a motor will have sufficient thermal capacity to dissipate energy losses while bringing the load up to speed. . Because of their inherently large physical proportions and resulting high load Wk^2, fans, blowers, and other machines used for impelling low density materials usually require a longer than normal time for acceleration.

Determining time for load acceleration

All other things being equal, the time required to accelerate a given drive is a direct function of its load inertia as expressed in the formula:

$$t = \frac{Wk^2 \times \text{rpm}}{307.5 \times T_a}$$

where t = time in seconds.

Wk^2 = inertia of the driven machine* and the motor in lb-ft^2.

T_a = torque in ft-lb available for acceleration of inertia, which is equal to motor torque less torque required by actual load on the driven machine.

rpm = motor speed at full load.

* If load speed is different than motor speed, the equivalent load Wk^2 at the motor shaft is: (load speed/motor speed)^2 × load Wk^2.

Starting time varies widely for a given horsepower input, depending upon the load Wk^2 of the driven machine. Using full-voltage starting, starting time may be as low as three to five seconds for a driven machine with low Wk^2. A centrifugal pump starting with the discharge valve closed and a motor-generator set without load are typical of driven machines that can be brought to speed quickly. Machines designed for handling materials of higher specific gravity, such as centrifugal pumps handling liquids, all have relatively low inertia. At the other extreme are high inertia drives, such as fans, blowers, and compressors, which may require 40 seconds or more to accelerate to full speed.

A starting time of up to 15 or 20 seconds is usually considered normal for standard cage motors, while periods exceeding 20 seconds are considered abnormal. All applications in which starting time exceeds 30 seconds, and most exceeding 20 seconds, must be considered special and require motors of special design.

Frequently, high torque motors are considered for high inertia loads. Their shorter starting time does reduce stator heating, since the stator winding carries starting current for a shorter time. However, heating of the cage winding resulting from acceleration of load inertia is not reduced. The energy which must be absorbed by and dissipated from the cage winding because of load inertia acceleration is equal to the kinetic energy stored in the rotating parts at full speed and is independent of time. A shorter starting time helps only in reducing cage winding losses resulting from the actual load on the driven machine.

The ability of a cage winding to handle a high load Wk^2 application is a function of its thermal capacity, that is, its ability to dissipate energy losses without the winding exceeding safe operating temperature. This heat-dissipating ability, which may be expressed in several ways—

one of which is kilowatt-seconds per pound of cage material — is not usually available unless a motor has been designed specifically for a particular application.

Load inertia for standard motors is limited

In order to simplify the problem of applying standard squirrel-cage motors rated 200 hp and larger to marginal high inertia loads, the National Electrical Manufacturers Association has added a table of "Authorized Engineering Information" to the "Motor and Generator Standards" indicating the maximum load Wk^2 of machines to which standard cage motors can be applied. These values, shown in Table I, are based on industry-wide experience and design practice, and are predicated on the following conditions:

First, they are based on motors having normal-torque characteristics and a temperature rise of 40 C by thermometer at full load. Higher rated temperatures generally will mean reduced load Wk^2 values; for example, a 100 C rise silicone-insulated motor may use the next or second smaller 40 C rise frame, with a consequent reduction in the cage winding thermal capacity.

Second, these values are based on a load-torque requirement varying as the square of the speed, such as a "fan-type" load. Should the load torque exceed that condition, the torque available for load Wk^2 acceleration will decrease proportionately.

Third, the number of successive starts is definitely limited. If, in addition to accelerating high inertia and providing the load torque, a motor is subjected to repeated starts without sufficient time intervals to allow the motor to return to or near rated normal operating temperatures, the heating effect would be cumulative and could prove destructive. Even though the winding does not fail at once, the bars and end-rings may become embrittled by excessive heating and eventually crack and become inoperative.

Special designs may be required

It is of course only natural to try to apply the simple cage motor and its equally simple control to every constant-speed drive. Not only is the cage motor a sturdy and reliable piece of equipment, but for most applications it is also the most economical. However, where the load Wk^2 exceeds that shown in Table I by any considerable amount, and the number of successive starts is excessive, even a cage motor is brought to the ragged edge of reliability.

TABLE I

The following table lists load Wk^2 which standard, polyphase squirrel-cage motors, larger than 200 horsepower, having locked-rotor torques equal to 60 percent of the full-load torque and a rated temperature rise of 40 C, can accelerate without injurious temperature rise under the following conditions:

1. Rated voltage and frequency applied.
2. During the accelerating period, the connected load torque shall be equal to, or less than, a torque which varies as the square of the speed and is equal to 100 percent of full-load torque at rated speed.
3. Two successive starts with the motor at ambient temperature, or one start with the motor not exceeding rated temperature. Subsequently, the number of permissible starts will depend upon the time required to accelerate the load from standstill to full speed, the thermal capacity of the motor and the time required for the motor temperature to return to rated temperature after each such start.

	Synchronous Speed, RPM Load Wk^2 in $lb\text{-}ft^2$ (Exclusive of Motor Wk^2)											
HP Rating	3600	1800	1200	900	720	600	514	450	400	360	327	300
250	229	1235	3185	6480	10900	16950	24350	33650	44600	57500	72400	89100
300	263	1390	3680	7340	12540	19500	28150	38750	51400	66200	83400	102500
350	298	1585	4165	8310	14200	22100	31850	43850	58200	74900	94400	116000
400	333	1755	4650	9270	15850	24650	34500	48950	64900	83600	105300	129500
450	367	1940	5130	10240	17500	27200	39250	54000	71700	92300	116300	143000
500	402	2120	5620	11200	19150	29750	42950	59100	78400	101000	127200	156400
600	472	2490	6590	13140	22450	34900	50400	69400	92000	118500	149300	183500
700	541	2855	7550	15070	25750	40050	57800	79600	105500	135900	171200	210400
800	610	3220	8520	17000	29050	45200	65200	89800	119000	153400	194200	237500
900	680	3590	9490	18940	32350	50300	72600	100000	132500	170800	215000	264500
1000	750	3950	10450	20860	35650	55500	80000	110100	146000	188200	237000	291500
1250	923	4870	12870	25700	43900	68300	98500	135600	179800	231700	292000	359000
1500	1095	5780	15300	30500	52150	81000	117000	161100	213600	275300	346600	426500
1750	1270	6700	17720	35360	60400	94000	135500	186700	247500	319000	401700	494000
2000	1440	7620	20130	40400	68700	106700	154000	212000	281400	362500	456500	561000
2250	1615	8530	22550	45000	76900	119600	172500	237600	315000	406000	511500	629000
2500	1790	9450	25000	49850	85200	132500	191200	263000	349000	449500	566000	696000

The increased thermal capacity required for these applications will probably mean a special motor and higher initial costs.

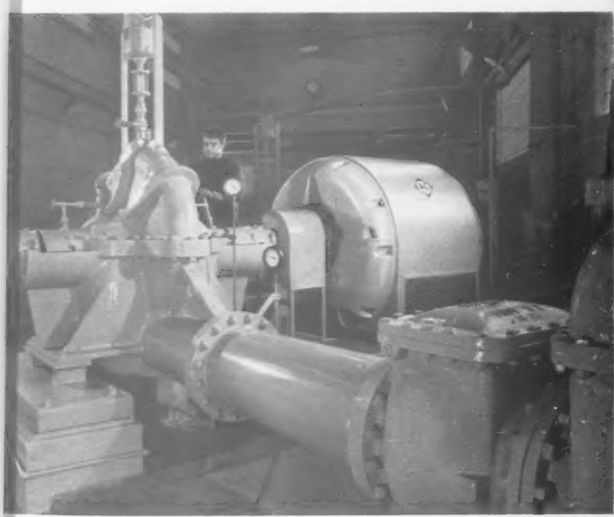
Although some added thermal capacity can be built into a squirrel-cage motor by changing the shape and cross section of the component members of the cage winding, available winding space is limited and consequently limits the additional thermal capacity available from this source. Frequently, a motor of special design with larger than normal frame size is essential if a squirrel-cage motor is to be used for a long starting period high inertia load.

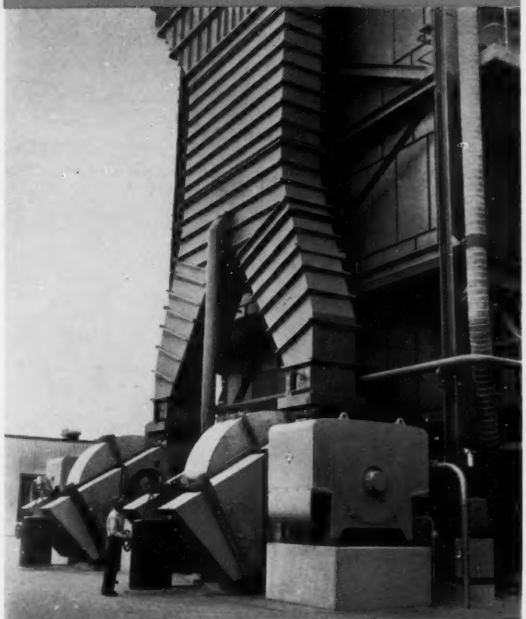
For applications that would require special squirrel-cage motors because of adverse inertia conditions, wound-rotor motors certainly deserve consideration. Since rotor circuit losses are largely dissipated in the external resistor, the rotor winding is never subjected to the extreme heating and cooling cycles encountered by a squirrel-cage winding. Also, the starting currents in the stator windings are of much lower values than in the cage motor. Hence, except as imposed by secondary resistor duty classification, there will be very little limitation on the number of repeated starts. Wound-rotor motors have a further advantage if speed regulation is a requirement of the application.

Objections to the use of wound-rotor induction motors for high Wk^2 loads include higher costs for both motor and control as well as slightly reduced reliability because of the added electrically active parts of the rotor winding, collector rings, and brush rigging.

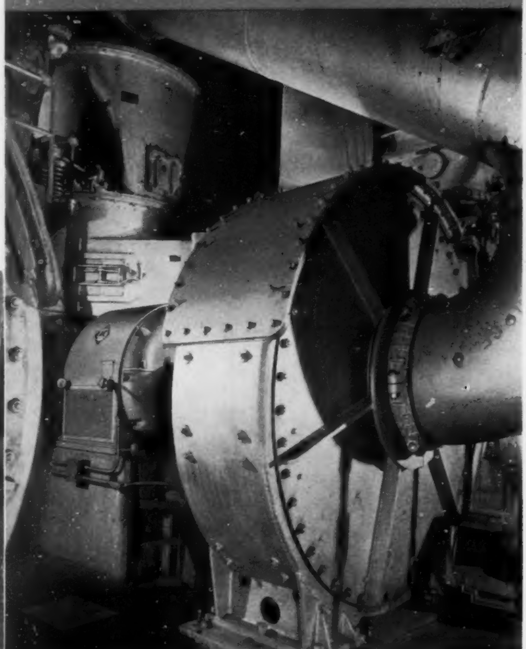
Squirrel-cage motors can, of course, be built for high load Wk^2 applications. However, if a squirrel-cage motor of special design is required, the wound-rotor motor should also be given adequate consideration, and the final selection based on the specific requirements of the application.

LOAD INERTIA ACCELERATION of a centrifugal pump, such as this 10,450-gpm, 180-ft head unit, imposes no special requirements on its 600-hp, 700-rpm squirrel-cage induction drive motor. **(FIGURE 2)**





WEATHER-PROTECTED outdoor squirrel-cage motors rated 1250 hp, 880 rpm, drive high inertia load forced draft fans (28,100 lb-ft^2) at this power station. **(FIGURE 3)**



THIS COAL MILL imposes a load of 2931 lb-ft^2, in addition to high breakaway torque requirements, on its 400-hp, 880-rpm drive motor which operates at 4000 volts. **(FIG. 4)**

AUTOMATIC LOAD TRANSFER

Cuts power interruptions from seconds to cycles

by **W. E. SCHWARTZBURG**
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MOMENTARY POWER INTERRUPTIONS can result in plant shutdowns and losses measured in thousands of dollars if continuous chemical or drug-processing lines are involved. In hospitals a power interruption may mean loss of life, while in places where large groups of people congregate at night, it can prove disastrous because a crowd may panic within a few seconds if plunged into total darkness.

Although power interruptions cannot be eliminated, their duration and effect in applications of this type can usually be minimized by providing a second power source and some method of automatic load transfer to the second source.

In comparatively small power applications, satisfactory operation can be obtained by providing emergency stand-by equipment. For example, most hospitals today are provided with equipment which will go into operation automatically if power is interrupted. Small diesel or gasoline engine driven generators can quickly pick up the entire load. Critical areas that cannot tolerate even a momentary interruption, such as operating rooms, are also provided with a battery-operated lighting system.

When applications involve large blocks of electrical energy, it is of course impossible to solve the problem in this manner. In a midwestern oil refinery, for example, it was calculated that an emergency shutdown would cost $60,000 because of the continuous processes involved and the minimum time of six days that would be required to get back into normal operation. When design engineers are confronted with figures of this magnitude, it is essential that they do everything possible to avoid an outage. The problem is a complex one and its solution must be evaluated from many angles.

Utility practices reduce outages

Electrical utilities are very conscious of the need for service continuity and of the losses that can result from any power interruption. Consequently, through years of diligent effort, utilities have eliminated a great many of the factors which might contribute to outages. Advanced planning has all but eliminated power interruptions due to foreseeable equipment failures.

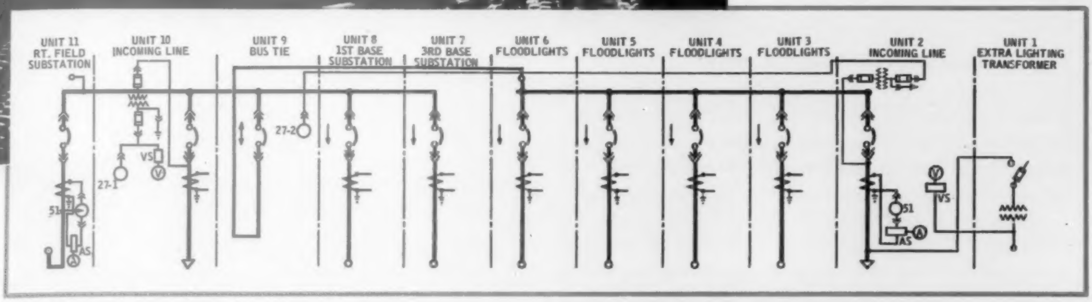
Beginning with the generating station itself, most utilities operate with a "spinning reserve" at least equal in kw to the largest single machine on the system. By operating in this manner, if any given machine is lost, the load is immediately picked up by the reserve machines already synchronized to the bus. Throughout the generation, transmission and distribution system, similar operating procedures are followed.

Of course, everyone in the electrical industry recognizes that there are outages which are impossible to prevent and over which the utility has no control. Lightning and wind storms are taken into consideration in the design of any transmission line, generating station or substation. The factors considered vary, depending upon the geographical location, since some sections of the country are confronted with storms of greater severity than others.

Despite all the efforts utilities make to assure service continuity, outages do occur. What can power users do to assure themselves that everything possible has been done to eliminate costly outages? To follow the utility power plant practice of providing stand-by equipment would be extremely costly and normally prohibitive. Suppling duplicate equipment is usually not the answer; a more practical solution is to arrange for a second source of power. When a second source is available, automatic transfer to the emergency line will prevent an outage if voltage fails on the normal line. The only additional equipment needed is a switching and control system to provide high speed auto-

TWO INCOMING LINES and automatic throw-over equipment assure continuous lighting for Milwaukee Braves home night baseball games. **(FIGURE 1)**

NORMALLY CLOSED incoming line breakers and the normally open tie breaker are indicated in this single-line diagram of the stadium. **(FIGURE 2)**

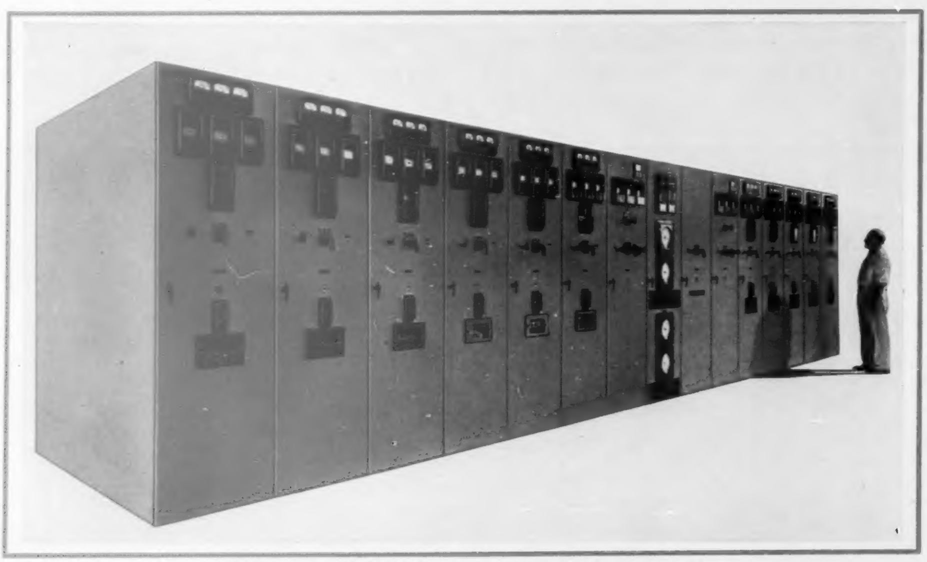


matic throw-over. The control problem and specific equipment needed to accomplish this transfer vary with each individual application.

Lines and load influence throw-over design

When planning an automatic throw-over system, a logical starting point is to determine the characteristics of the two incoming lines. If the two line voltages are always in phase and of the same magnitude, then a single bus could be fed from these two sources. Normally, however, two lines that are electrically isolated cannot be continuously paralleled. The use of two buses tied together with a normally open bus-tie breaker working in conjunction with two normally closed incoming line breakers is an acceptable solution.

When the Milwaukee County Stadium, shown in Figure 1, was built in 1952, its lighting system was fed from a high voltage transmission line through a single step-down transformer, the secondary of which was connected to the stadium's incoming line breaker. After a year of operation, an additional source of power was considered essential, and arrangements were made with the local utility to provide it. A second high voltage line was made available, a second step-down transformer was purchased and the switchgear bus was rearranged to provide automatic throw-over. Information supplied by the utility indicated that the two transformers' secondaries could be momentarily but not continuously paralleled. Since the load is all lighting, a high speed throw-over scheme was used. The two incoming line breakers operate normally closed,



TYPICAL OF SWITCHGEAR for automatic load transfer, this equipment is installed in a south-central power plant. **(FIGURE 3)**

the bus tie normally open. A single-line diagram of the arrangement is shown in Figure 2. If a voltage failure should occur on either incoming supply line, that breaker will be tripped by undervoltage relays and the new bus-tie breaker will automatically close. Upon restoration of voltage on the tripped line, the previously opened breaker closes and the tie breaker trips. An explanation of the schematic diagram, Figure 4, will show how this has been done.

How one throw-over scheme works

Unit number 2 is one incoming line breaker, unit number 10 the other, and unit number 9 is the normally open bus-tie breaker. Device 43 is a switch which allows the operator to choose between manual and automatic operation of the circuit breakers. With normal voltage on both incoming lines and device 43 in the manual position, the two incoming line breakers are closed electrically by the operator. Before device 43 is turned to the automatic position, the bus-tie breaker should be opened or else it will be tripped automatically when 43 is turned to the automatic position through contacts T4-8 and the two undervoltage relay contacts 27-1 and 27-2, which are closed with normal voltage on the two incoming lines.

Assume that while carrying normal load through the two incoming line breakers, with device 43 in the automatic position, voltage fails on breaker number 2, as detected by undervoltage relay 27-2. The normally closed contact in the trip coil circuit of breaker number 2 will close, and the breaker will trip through contacts T6-12 of device 43. The bus-tie breaker will then close through contacts T5-9 of device 43, the *'b'* switch of breaker 252 (which closes when breaker 252 opens), the normally closed and slip contact of breaker 252's control switch, relay 4's normally closed contact and the normally closed contacts of lockout relays 86-B1 and 86-B2. The purpose for using a normally closed control switch and slip contacts is to prevent closing of the bus-tie breaker if the operator trips breaker 252 manually while device 43 is in the automatic position. If for any reason incoming line breaker 1052 is open, nothing is gained by closing 952. For that reason, a *'b'* switch for each breaker is wired in series with relay 4, to prevent closing 952.

If a short circuit condition exists on the bus, a throw-over would be undesirable. For this reason lockout relays 86-B1 and 86-B2 are wired in series with the tripping contacts of the overcurrent relay (device 51) to prevent automatic closing of breaker 952.

Thus it can be seen that with an undervoltage condition on breaker 252, 252 will trip and 952 will close. Upon restoration of normal voltage, the normally open undervoltage contacts of 27-1 will close, thus tripping the bus-tie breaker. When breaker 952 opens, closing its *'b'* switch in the closing circuit of breaker 252, breaker 252 closes through contacts T5-10 of device 43 and the normally closed contacts of 86-B2.

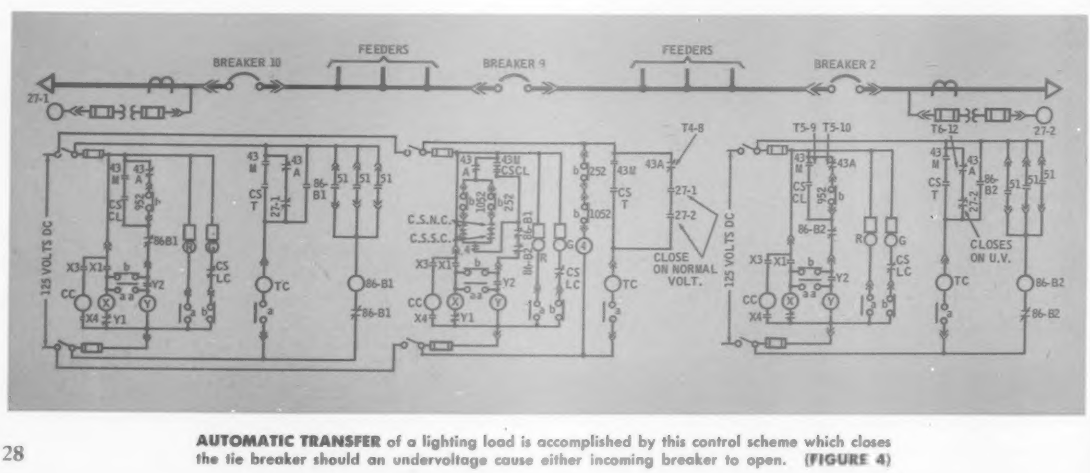
No intentional time delay is incorporated in this scheme. This scheme is inexpensive, as it operates through breaker auxiliary switches. No auxiliary relays are required except device 4 and the automatic manual selector switch.

After normal voltage has failed on either incoming line, the bus-tie breaker closes as soon as the incoming line breaker reaches a fully open position. This is unusual in an automatic throw-over scheme and is possible only because the load is practically all lighting.

Throw-over schemes for motor loads are more complex

When power being fed to motors fails, the motors will generate a voltage during the time required to complete throw-over. This poses the problem of trying to synchronize across the bus-tie breaker with no control over either voltage. After the incoming line breaker opens because of an undervoltage condition, there still is a voltage on the bus. This voltage, generated by the rotating equipment, is decreasing in magnitude as frequency diminishes from the original 60 cycles to zero.

If synchronizing check relays are used as part of the throw-over scheme, provision must be made to block them



AUTOMATIC TRANSFER of a lighting load is accomplished by this control scheme which closes the tie breaker should an undervoltage cause either incoming breaker to open. **(FIGURE 4)**

out when the frequency of the undervoltage bus reaches zero. This is necessary since the residual motor voltage and the incoming line may never offer an in-phase condition of correct magnitude to the synchronizing relay. If the throw-over is held back until there is no longer any residual motor voltage, there will be an interruption of power and the bus-tie breaker will have to close in on a "dead" bus. This would present the problem of restarting the motors, with the resultant high current flow which may trip out the other incoming line breaker overcurrent relays. Since the main objective is keeping both buses energized, the transfer should occur while the motors are still running, but at a point where the residual motor voltage will not be of sufficient magnitude to damage the motors.

At this point a logical question is, "How long does a motor continue to generate a voltage after it is de-energized?" If a synchronous motor is being considered, this interval will depend upon the Wk^2 of the motor and its connected load. A squirrel-cage induction motor will also generate a voltage when it is de-energized, because of self-induction. The rotor current continues to flow after the primary voltage is removed, and this current tends to maintain the magnetic field. The field rotates at motor shaft speed and generates a back voltage of corresponding frequency in the stator. This condition can last for a comparatively long interval.

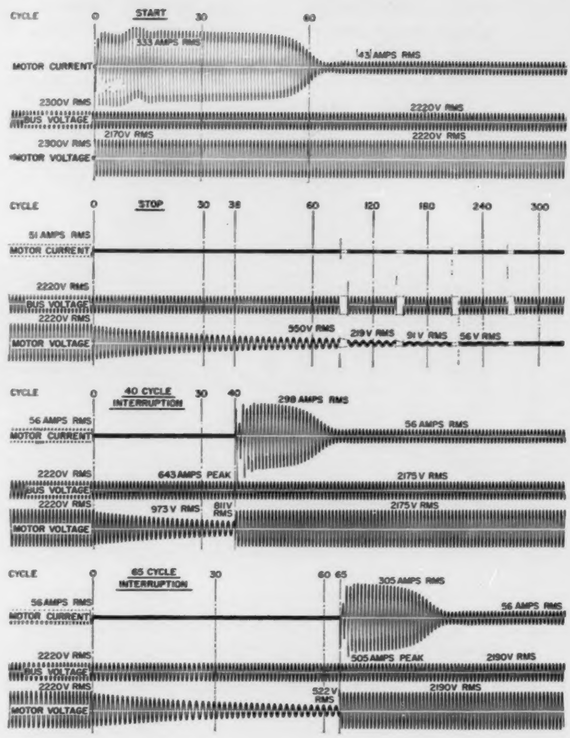
Oscillograms measure voltage

This phenomenon has been proved by actual tests. Figure 5 shows the results obtained when testing a 250-hp, 2300-volt, 1800-rpm induction motor driving a general service pump. The first group of curves shows a normal starting operation with records of motor starting current, bus voltage and motor terminal voltage. The locked-rotor or starting current was 333 rms amperes. The normal full-load value of 43 rms amperes was reached in 60 cycles.

During this test the bus and motor voltage were of the same magnitude, 2220 rms volts. The second group of curves shows the same quantities when the motor was disconnected from the bus in a normal stop. The current goes to zero, the bus voltage remains constant and the motor generates a voltage for approximately 240 cycles. At the end of one second, the motor voltage is 550 volts, or almost 25 percent of normal bus voltage.

To determine the values of inrush current that would be encountered upon re-energizing the motor, two additional tests were made with the motor running, then disconnected and again connected. The third set of curves shows a 40-cycle interruption, the motor reconnected to the bus with the motor residual voltage at 811 rms volts. Under this condition the current inrush reached a peak value of 643 amperes. The fourth set of curves shows the results of a similar test with an interruption of 65 cycles, a motor residual voltage of 522 rms volts and 505 amperes peak inrush.

These test oscillograms indicate that it is possible to reach a current inrush sufficiently high to damage the



TRANSFER OF MOTOR LOADS **requires a more complex scheme because motors connected to the bus generate a voltage when driven by inertia after an incoming line failure, as indicated by these oscillograms of a 250-hp, 1800-rpm motor driving a pump. (FIG. 5)**

motor if it is connected to a voltage supply 180 degrees out of phase with the residual voltage being generated.*

One way to eliminate this problem of high inrush on automatic throw-over is to introduce a time delay to make certain the residual voltage will decay to a safe value. This can be accomplished by a relay which is normally set to give a delay of approximately 50 cycles. Either a motor-driven or pneumatic timing relay can be used in this application. The control circuit will be designed so that the incoming line breaker will trip on undervoltage, and the tie breaker close after the time delay, which is initiated by a *"b"* switch of the incoming line breaker.

Another method of introducing a time delay could be provided by using an instantaneous undervoltage relay connected to the bus potential transformers. If the incoming line breaker would be tripped by the time-delay undervoltage relays, the bus-tie breaker would not close

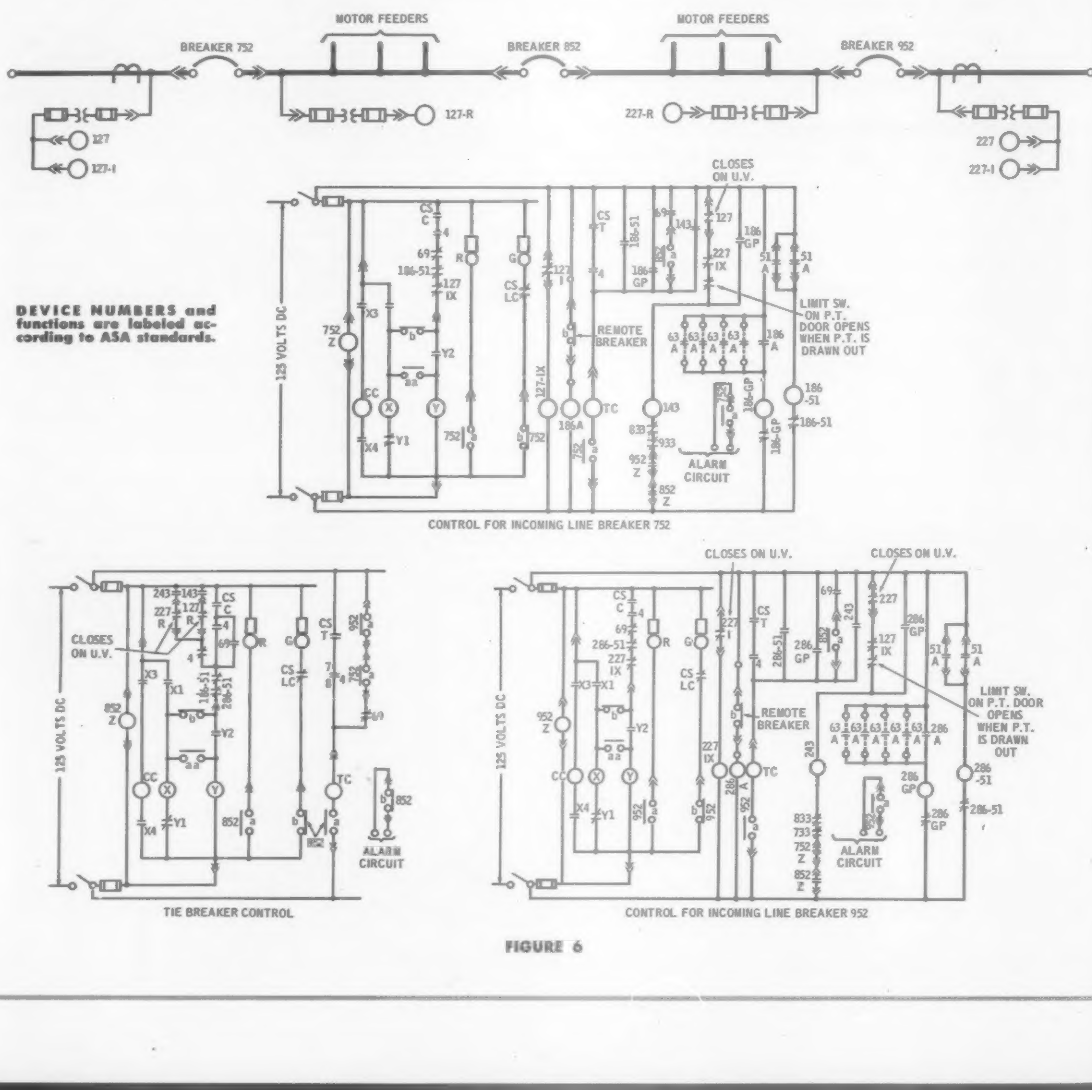
* These tests were run by a utility, and the oscillograms were published in an article entitled "Operating Experiences with Power Plant Auxiliary Systems," by H. F. Tevlin and L. H. Romzick (AIEE Miscellaneous paper 52-289).

until residual bus voltage drops to a safe value as determined by the instantaneous undervoltage bus relays. This specially calibrated relay would be set to close its contacts when the voltage decays to about 25 percent of normal value. In this method of time delay, the throw-over will be completed in minimum time, and the problem of using an arbitrary figure for the setting of the timing relay is not required. This scheme has been used by several oil refineries and performed satisfactorily when field tested.

There are, of course, innumerable ways to design control circuits for automatic load transfer schemes. Only two have been shown — Figure 4, a scheme for a lighting load, and Figure 6, for a motor load. Every application poses its own individual problems and involves various forms of mechanical and electrical interlocks in the switchgear. However, in practically every application requiring a continuous power supply, automatic load transfer equipment can be designed to minimize any outages that may occur.

USED FOR A MOTOR LOAD, this automatic transfer scheme utilizes specially calibrated instantaneous undervoltage relays to hold back closing of bus-tie breaker 852 until residual voltage decays to a safe value. In normal operating procedure, with normal voltage on relays 127 and 227, incoming line breakers 752 and 952 are closed and bus-tie breaker 852 is open. If undervoltage occurs on either of the two incoming lines and there is at least 75 percent voltage on the other line, as determined by relays 127-1 and 227-1, an automatic throw-over will be initiated. This is done by picking up relays 143 and 243 through the normally closed contacts of breaker cell switches 833 and 733 or 933 and control voltage relays 852Z and 952Z or 752Z. Relay 143 or 243 then trips the incoming line breaker and closes the bus-tie breaker. The bus-tie breaker will not close unless residual voltage on the de-energized bus has decayed to 25 percent of normal, as determined by relays 127-R and 227-R. Also, the bus-tie breaker will not close if either of the two incoming line breakers has tripped because of an overcurrent condition, as checked by the normally closed contacts of overcurrent lockout relays 186-51 and 286-51.

This scheme holds back a load transfer until the residual voltage has reached a predetermined value. It will be noted that no synchronous or pneumatic timers are needed and that the time delay is not necessarily a constant value. If the voltage decays to a safe value in 20 cycles, then a transfer operation will take place in that time. This method eliminates any assumed time settings and assures a transfer in an absolute minimum interval.



DEVICE NUMBERS and functions are labeled according to ASA standards.

FIGURE 6